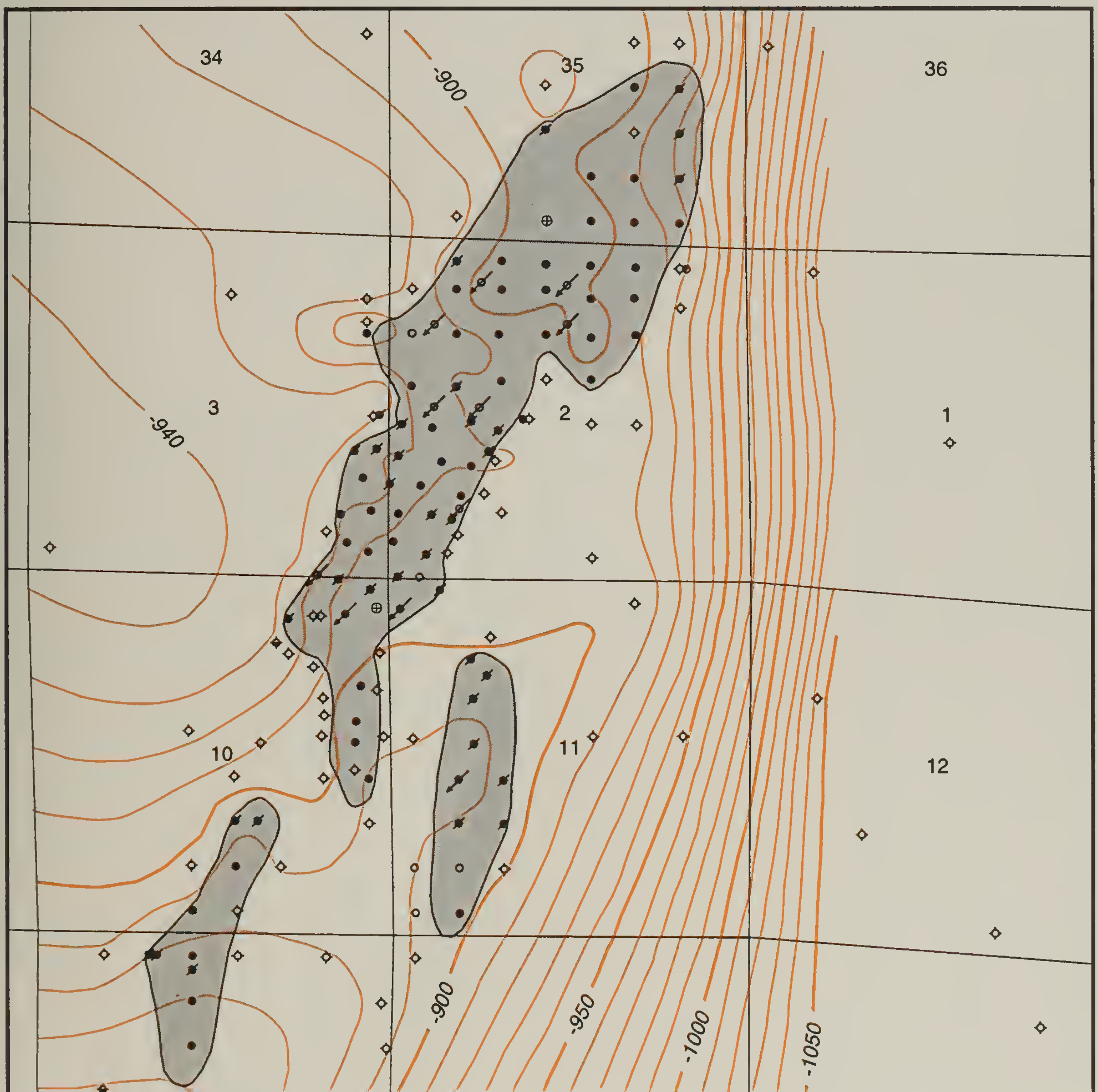
Reservoir Characterization and Its Application to Improved Oil Recovery from the Cypress Formation (Mississippian) at Richview Field, Washington County, Illinois

John P. Grube and Wayne T. Frankie



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Department of Natural Resources
ILLINOIS STATE GEOLOGICAL SURVEY

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DISCLAIMER

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ABSTRACT

Richview Field, discovered in 1946, is located in eastern Washington County, south-central Illinois. Petroleum is produced from northeast–southwest trending, vertically stacked, lenticular sandstone bodies in the upper part of the Mississippian Cypress Formation. The sandstone lenses that make up the primary reservoirs range from 1 to 2 miles in length, are up to ½ mile in width, and average 10 feet in thickness. Reservoir porosity averages 20%, and permeability averages 175 millidarcies. The reservoirs extend over 640 acres at an average depth of 1,500 feet. Discrete reservoir compartments are created within the field by shale beds that separate the vertically stacked sandstone lenses. Combined stratigraphic/structural trapping occurs where stacked, compartmentalized sandstone lenses lap onto and drape over a structural saddle. Geometry and stratigraphic associations indicate that these sandstones were deposited in shallow coastal marine environments.

Diagenesis has affected the quality of the sandstone reservoirs at Richview Field. Quartz cementation has reduced permeability and porosity within the reservoirs. Diagenetic clay minerals, including kaolinite, mixed-layered illite/smectite, and iron-rich chlorite, are common constituents within these sandstones. Although clay minerals constitute only about 5% by weight of the Richview sandstone reservoirs, their potential to cause formation damage can be large. The introduction of water into a reservoir that is less saline than the native brine can cause kaolinite and illite/smectite to react in ways that decrease permeability. Hydrochloric acid can react with iron chlorite to form iron hydroxides, which can also reduce permeability.

Maintenance of reservoir pressure has increased ultimate cumulative oil recovery. Initiation of waterflooding after as little as 1 year of primary production very likely increased recovery efficiency at Richview Field. Of the estimated 7.3 million barrels of stock tank original oil in place (STOOIP), 3.3 million barrels have been produced, yielding a recovery efficiency of 45.6%.

The study concludes that production can be optimized most efficiently by single-operator or unitized and coordinated projects, waterflood and pressure-maintenance programs, use of correct correlations in waterflood programs, and use of field pressure analyses to evaluate reservoir continuity and flow unit correlation. For Richview Field, infill drilling may prove feasible for increasing recovery efficency.

Clay damage caused by drilling and completion techniques can be avoided by clay stabilization systems, avoiding "water shock," addition of oxygen scavengers and iron chelating agents to acid, and introduction into a reservoir of fluids that are compatible with the clay minerals in the reservoir.

INTRODUCTION

The Mississippian Cypress Formation (fig. 1) is a major producing formation in the Illinois Basin. An estimated 800 million barrels of oil have been produced from Cypress sandstone reservoirs. Most of these reservoirs were discovered 30 to 60 years ago and are either depleted or undergoing secondary recovery operations. While primary and secondary production has drained a significant amount of the recoverable oil from these reservoirs, unswept mobile oil that may be economically recoverable remains.

A comprehensive geologic investigation integrated with engineering analysis of all production-related reservoir characteristics is necessary to identify and evaluate the

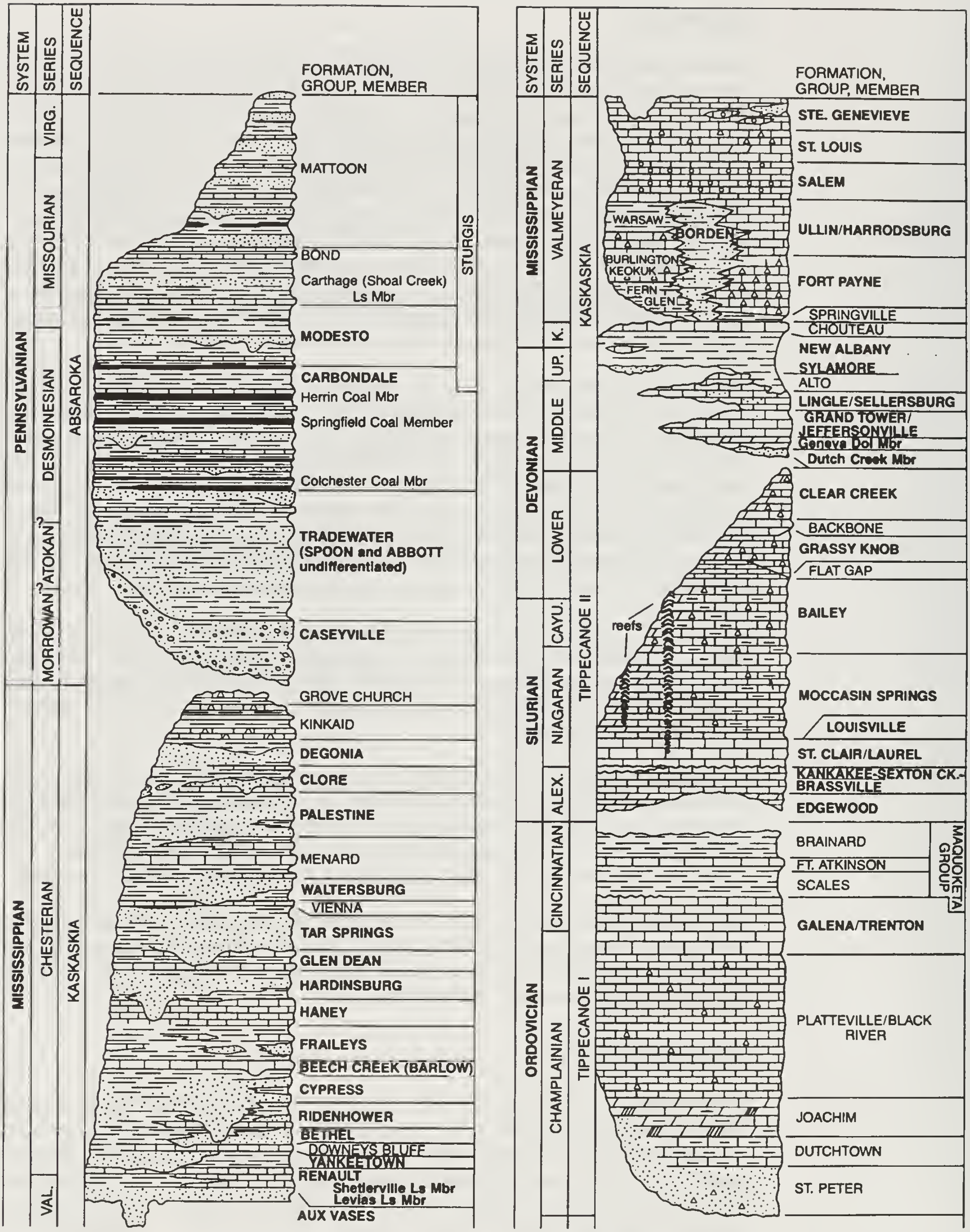


Figure 1 Generalized geologic column for southern Illinois. Rocks that underlie the St. Peter Formation are not shown. Formations or members that contain pay zones are given in bold type. The names Alexandrian, Cayugan, Upper Devonian, Kinderhookian, Valmeyeran, and Virgilian are abbreviated as Alex., Cayu., Up., K., Val., and Virg. Variable vertical scale (after Howard and Whitaker 1990).

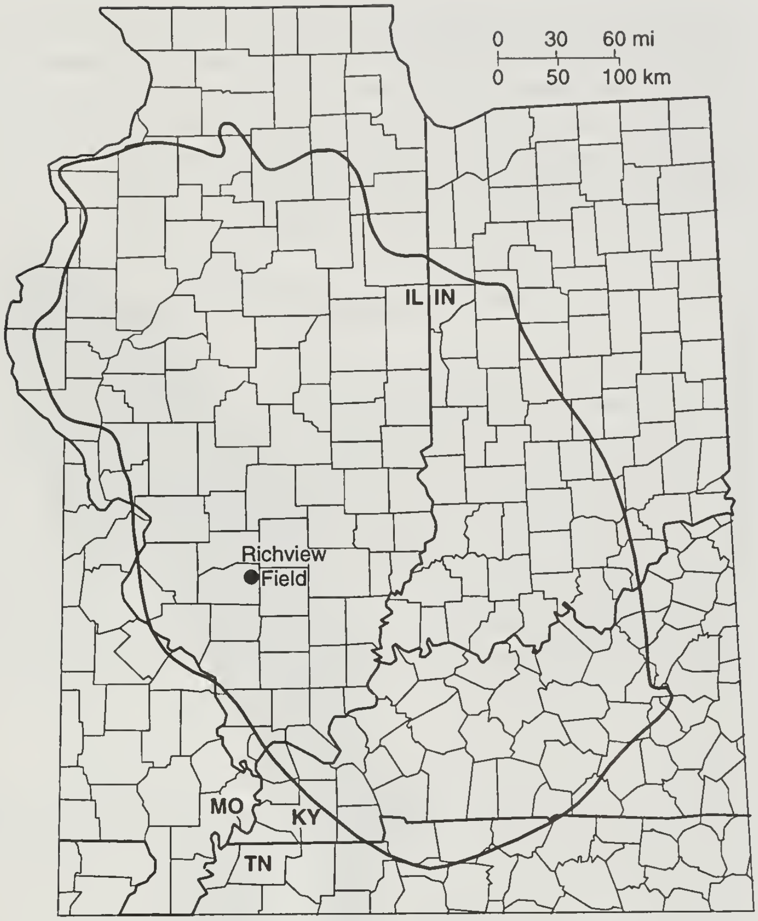


Figure 2 Richview Field and outline of the Illinois Basin.

potential to recover the remaining unswept mobile oil. Drilling, completion and stimulation methods, well spacing, pressure maintenance, and waterflood designs are highly dependent on the characteristics of individual reservoirs. This study was conducted to geologically characterize the Cypress sandstone reservoirs at Richview Field and to identify the factors that control recovery efficiencies. Techniques that may improve oil recoveries or have already been successfully employed to recover oil from the Richview reservoirs were also investigated in this study.

Richview Field is located in eastern Washington County, in south-central Illinois (fig. 2). The field trends northeast–southwest and underlies parts of Section 35, Township 1 South, Range 1 West, and portions of Sections 2, 3, 10, 11, and 15, Township 2 South, Range 1 West (fig. 3). The field is approximately 3 miles long, 0.5 to 0.75 miles wide, and is centered directly beneath the town of Richview. No obvious natural surface expressions of this oil field are apparent. As with many oil fields in the Illinois Basin, Quaternary cover tends to mask the underlying structural features at Richview.

This study was part of an investigation that was designed to improve and enhance oil recovery in Illinois through reservoir characterization. Funding for the investigation was provided by the Illinois Department of Energy and Natural Resources and the U.S. Department of Energy. Richview Field is one of seven Cypress oil fields chosen for study on the basis of availability of data, regional location, stratigraphic

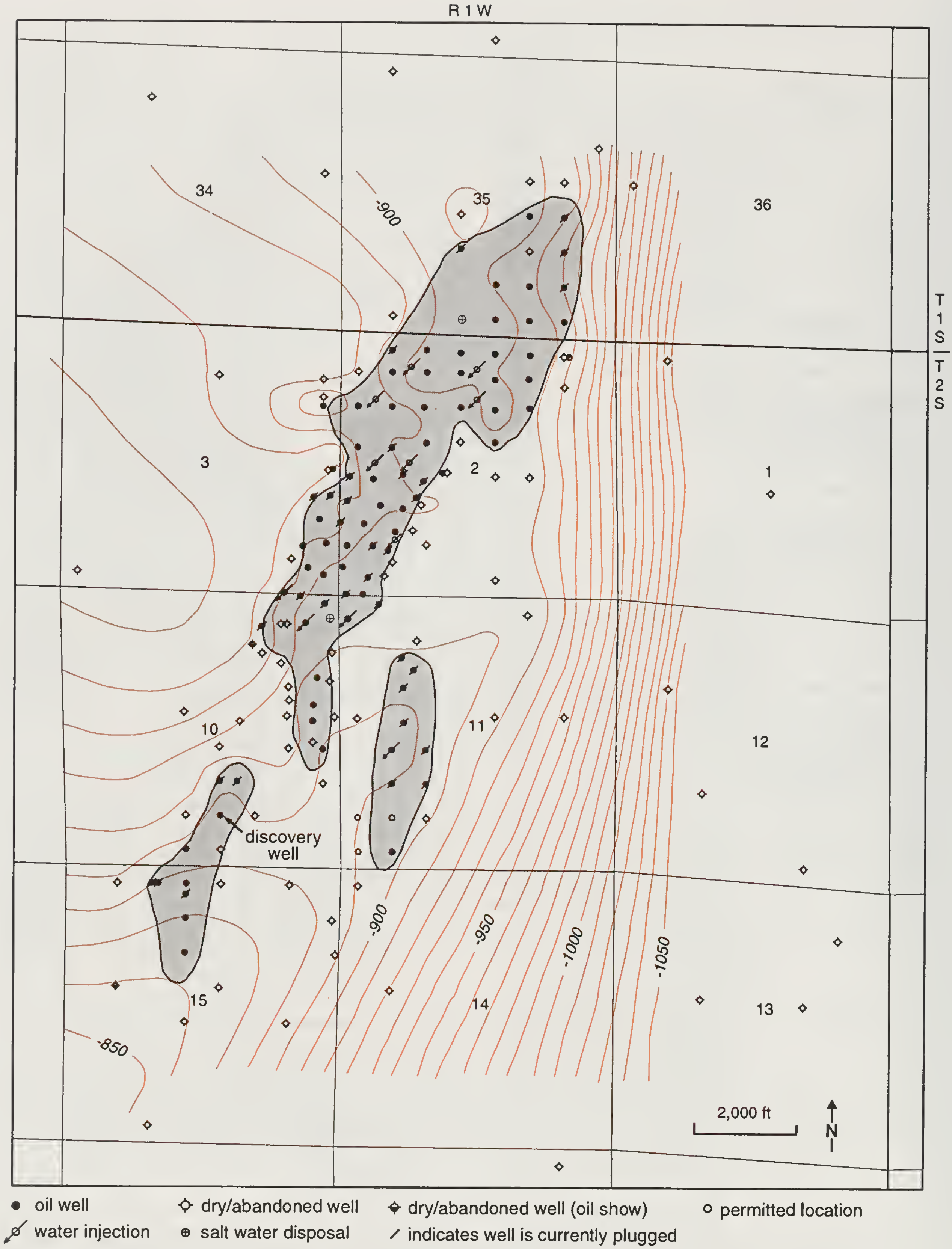


Figure 3 Structure map contoured on the top of the Beech Creek (Barlow) Limestone. Richview Field produces from a principal pool and two subsidiary pools offset to the southeast and southwest of the main pool. Contour interval is 10 feet.

position of the reservoir within the Cypress Formation, and cumulative production. A comprehensive evaluation of Cypress reservoirs and their respective characteristics was obtained by selecting fields that (1) produced from several distinct stratigraphic intervals within the Cypress Formation and (2) represented a diversity in location, cumulative production, reservoir development and management strategies, and company size. Many of the field studies have been published by the Illinois State Geological Survey, and all the studies are summarized in Oltz (1994).

FIELD DISCOVERY AND PRODUCTION HISTORY

Geologic Setting

Richview Field is situated on the west flank of the Illinois Basin. The field is on the uplifted side of the Du Quoin Monocline, immediately west of the monoclinal flexure. The monocline, a major structural feature in the basin, strikes north–south over a distance of 50 miles. Locally, more than 400 feet of structural relief occurs within a distance of approximately 1 mile on the Beech Creek (Barlow) Limestone across the flank of the monocline (fig. 3). Because the name Barlow is widely used to refer to the Beech Creek Limestone, the term Barlow will be employed in this publication. The Du Quoin Monocline marks the eastern edge of the Sparta Shelf, the structural terrace on which Richview Field is located (fig. 4). Subsidiary folds along the Du Quoin Monocline form the structural component of the hydrocarbon trap for the Richview reservoirs.

A structure map contoured on the base of the Barlow limestone (fig. 4) shows the location of Richview Field. Regional dip on the Barlow averages 30 feet per mile across the Illinois Basin. The Barlow is a widespread limestone that directly overlies the Cypress and is commonly used as a structural reference for the Cypress. Richview Field lies in a structural saddle between the Irvington Anticline to the north and the structural extension of that anticline to the south. The Irvington Anticline traps oil at Irvington Field, and the southern extension of that anticline traps oil at Ashley and Dubois Fields.

Changes in thickness of Pennsylvanian strata and indications of movement across the Du Quoin Monocline during earlier Paleozoic periods indicate that recurrent movement has taken place along a system of basement faults (Nelson 1995, Hopkins and Simon 1975). Folding that formed the Irvington Anticline and related structures that trap oil in the Irvington, Richview, and Ashley Fields may have resulted from tectonic events that created the Du Quoin Monocline; therefore, deformation formed the trap during and possibly after the Pennsylvanian Period (Siever 1951).

Relatively few Cypress oil fields have been established in this region, although Cypress sandstones are widespread across the west flank of the basin. In general, hydrocarbon production in these fields is limited to the uppermost Cypress sandstone, even though structural closure may exist throughout the entire formation. Therefore, the Cypress has not been fully charged with hydrocarbons.

Discovery History

Richview Field was discovered by the drilling and completion of the National Consumers Oil Company's No. 1 Pitchford-Koelling well on August 6, 1946. The well is located in the NW SW SE, Section 10, T2S, R1W, and was drilled to a depth of 1,532 feet. Initial production was 31 barrels of oil per day (BOPD) from the upper Cypress sandstone at 1,521 to 1,532 feet. Although the field was discovered in 1946, most of the development occurred in the early 1960s after Charles T. Evans drilled the No. 1

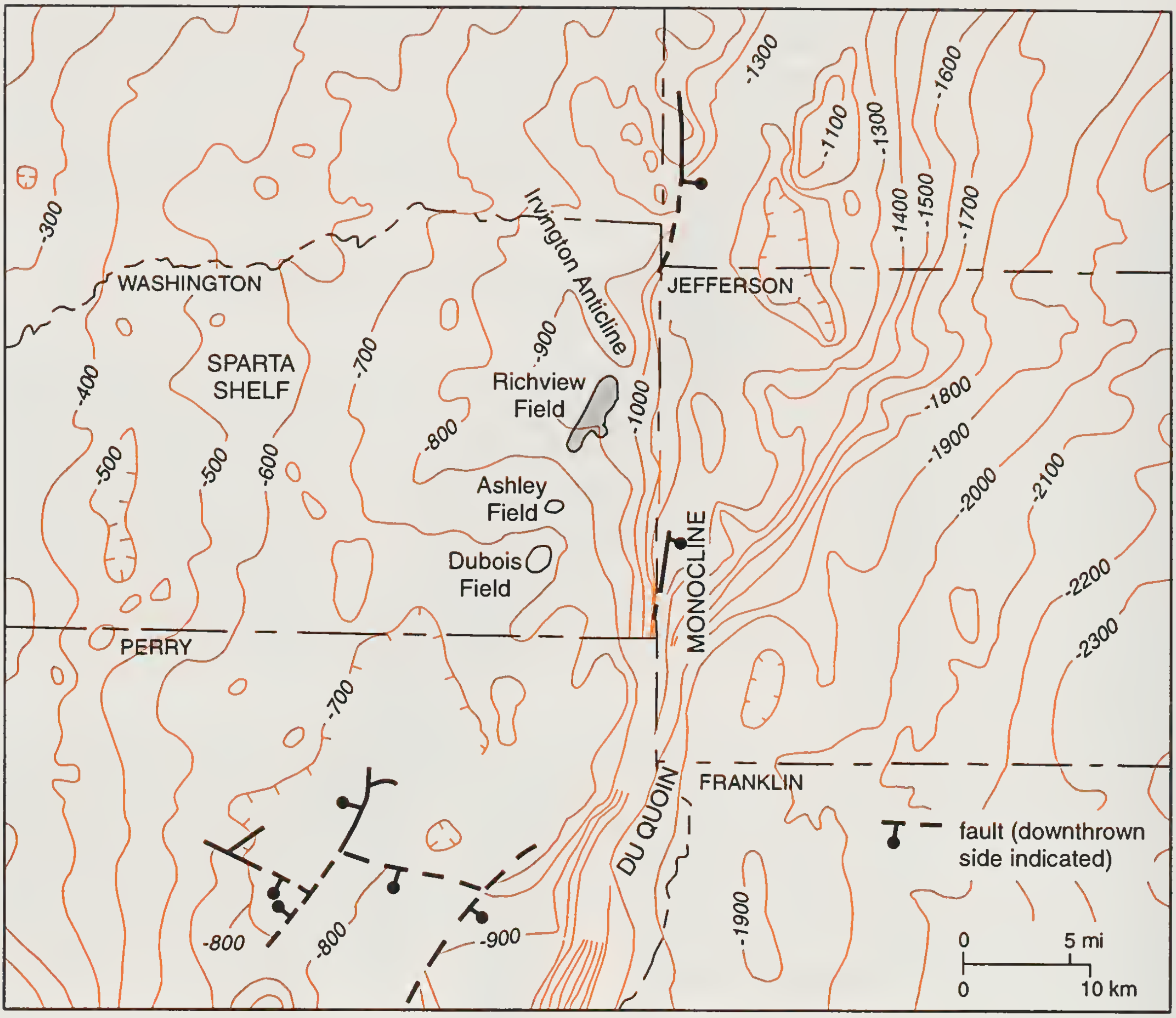


Figure 4 Structure map contoured on the base of the Beech Creek (Barlow) Limestone. The location of Richview Field on the west flank of the present structural basin is shown (after Bristol 1968). Contour interval is 100 feet.

Droege Unit in the SW SW NW, Section 2. The No. 1 Droege Unit, completed on September 27, 1961, discovered a Cypress pool that is separate from the initial discovery well in Section 10 and is the most extensive of the three pools that make up Richview Field. Centralia Petroleum Company established the third pool by completion of the No. 1 Koelling, SE NW SW, Section 11, in September 1962.

Records show that 89 wells were drilled and completed in the field. To date, 37 wells are recorded as plugged. The three pools that make up the field are outlined by 53 offsetting dry holes. The field contains approximately 640 acres of proven reserves.

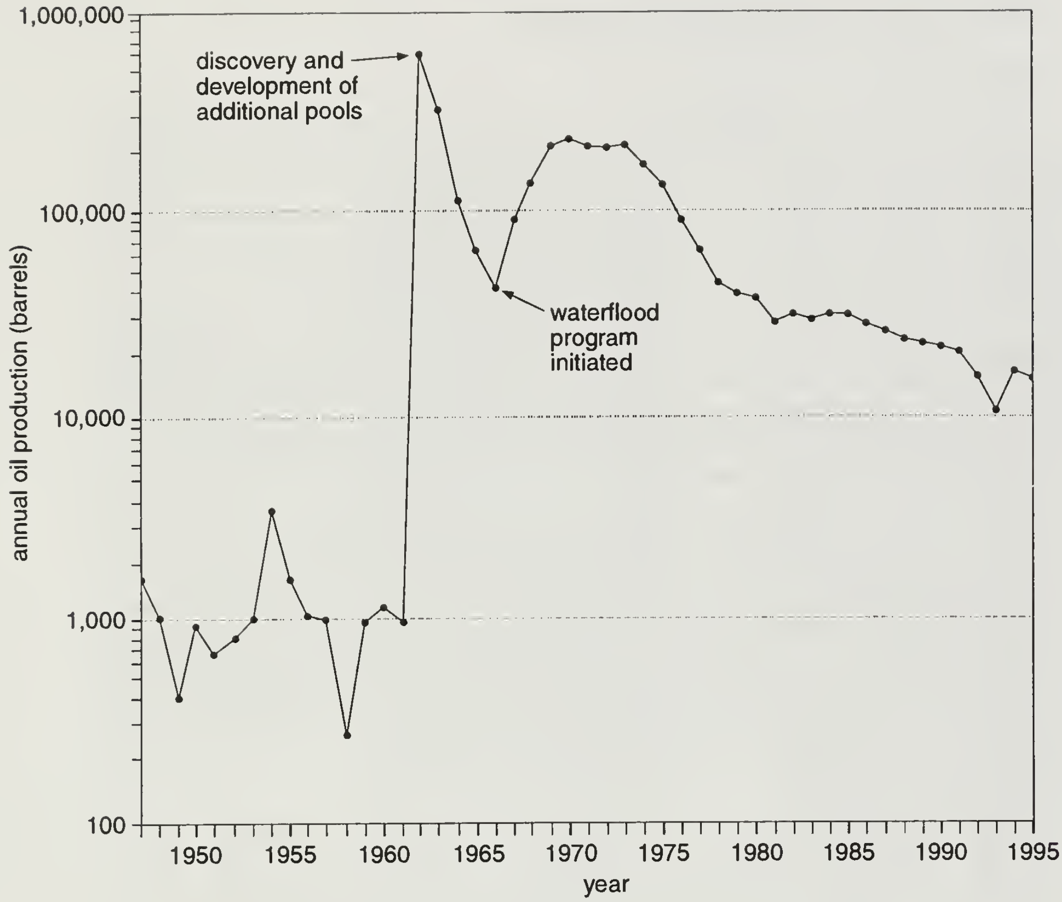


Figure 5 Decline curve for Richview Field, showing annual production for 1947–1995.

Production History

Figure 5 is a graph of yearly production. The first 16 years of production, from 1946 through 1961, was from two wells in the original discovery area in Section 10. Just under 17,000 barrels of oil were produced from the two wells through 1961. The large increase in production beginning in 1962 is the result of the discovery and concentrated development of the main pool and the subsidiary pool in Section 11. In 1962 the number of wells in the field increased to 39 and subsequently to 53 wells in 1963. Production wells are predominantly drilled on 10 acre spacing.

An increase in production starting in 1967 was the result of a waterflood program initiated in 1966. Six separate waterflood programs were established at Richview Field that effectively flattened and extended the decline curve (fig. 5). Injected water for waterflooding is derived from produced brine and supplementary water extracted from sandstones of the overlying Tar Springs Formation.

Cumulative production for the entire field from 1946 through1995 is 3.3 million barrels of oil. Records from the Section 11 subsidiary pool show a cumulative production of 125,000 barrels of oil. Records are incomplete for the original discovery pool in Sections 10 and 15. Data available from 4 of the 10 wells in this pool show production of 52,000 barrels of oil.

RESERVOIR CHARACTERIZATION

Stratigraphy

The Cypress Formation was deposited during a major pulse of siliciclastic sedimentation that occurred in the Illinois Basin during the early part of the Chesterian Epoch (fig. 1). A shallow cratonic sea initially occupied the Illinois Basin as the siliciclastic materials entered the Basin from the northeast (Potter et al. 1958, Swann 1963, Cole and Nelson 1995). The maximum thickness of the Cypress Formation at Richview Field, from the base of the overlying Barlow limestone to the base of the lowermost Cypress sandstone (fig. 6), is approximately 110 feet. The Cypress consists predominantly of sandstones and shales, with some siltstone, mudstone, and thin calcareous sandstones grading to limestones. Within the upper part of the Cypress, beds of impure coal or carbonaceous shale and regionally widespread variegated mudstones and mottled red and green mudstones are apparent on outcrops and in core and drill cuttings. These variegated mudstones and coaly deposits indicate that subaerial to near-subaerial exposure occurred after deposition of these muds. Also, some of the thick outcropping and subsurface sandstones that occur at or below the variegated horizon are interpreted by the authors to be incised valley fill deposits. Both the variegated rocks and the presence of incised valleys indicate that during deposition of the Cypress, widespread subaerial exposure occurred. Regional exposure surfaces such as these are defined in sequence stratigraphic analysis as sequence boundaries (Van Wagoner et al. 1990). Sequence boundaries are useful guides for the correlation of depositionally related facies and have practical application in defining reservoir compartments and trend direction.

Overlying the Cypress in the study area are 8 to 29 feet of Barlow limestone. Shales, siltstones, and thin limestones of the Ridenhower Formation underlie the Cypress Formation. Electric log signatures indicate that a well-developed Downeys Bluff Limestone underlies the Ridenhower. Because most of the wells did not penetrate the entire Cypress Formation, only limited data exist for the lower Cypress and the underlying section. Although well control is limited, there does not appear to be sandstone development within the Bethel-Ridenhower interval in the study area.

The reservoir at Richview Field was characterized, in part, through lithofacies mapping and depositional facies interpretation. Four separate reservoir intervals were defined within the Cypress on the basis of correlations of distinctive spontaneous potential (SP) and resistivity log signatures. Three correlation parameters were used to define the divisions: (1) similarity of log character, (2) stratigraphic position of sandstones in the Cypress Formation, and (3) stratigraphic position of shales in the Cypress Formation. Sandstones within these intervals have been designated in ascending order as the Cypress A, B, C, and D sandstones (fig. 6.). Shale or SP breaks are not apparent in the Cypress D sandstone, whereas breaks up to several feet thick are common in the sandstones of the Cypress B and C intervals. Shale breaks from less than 1 foot to several tens of feet thick occur between the individual sandstones of the Cypress A interval. Separate sandstone bodies that commonly stack and coalesce or split and pinchout make correlations uncertain even between wells drilled on 10 acre spacing. The designation Cypress A, B, or C sandstone, therefore, represents a composite or net of all sandstones that occur in their correlative interval rather than a reference to specific sandstone beds.

The Cypress A sandstone, usually composed of multiple benches, is varied in character and equivalent to the lower Cypress, blocky type sandstone common in fields east of the Du Quoin Monocline. Only a small amount of oil has been produced from this sandstone at Richview. The Cypress B and C sandstones, which form the most

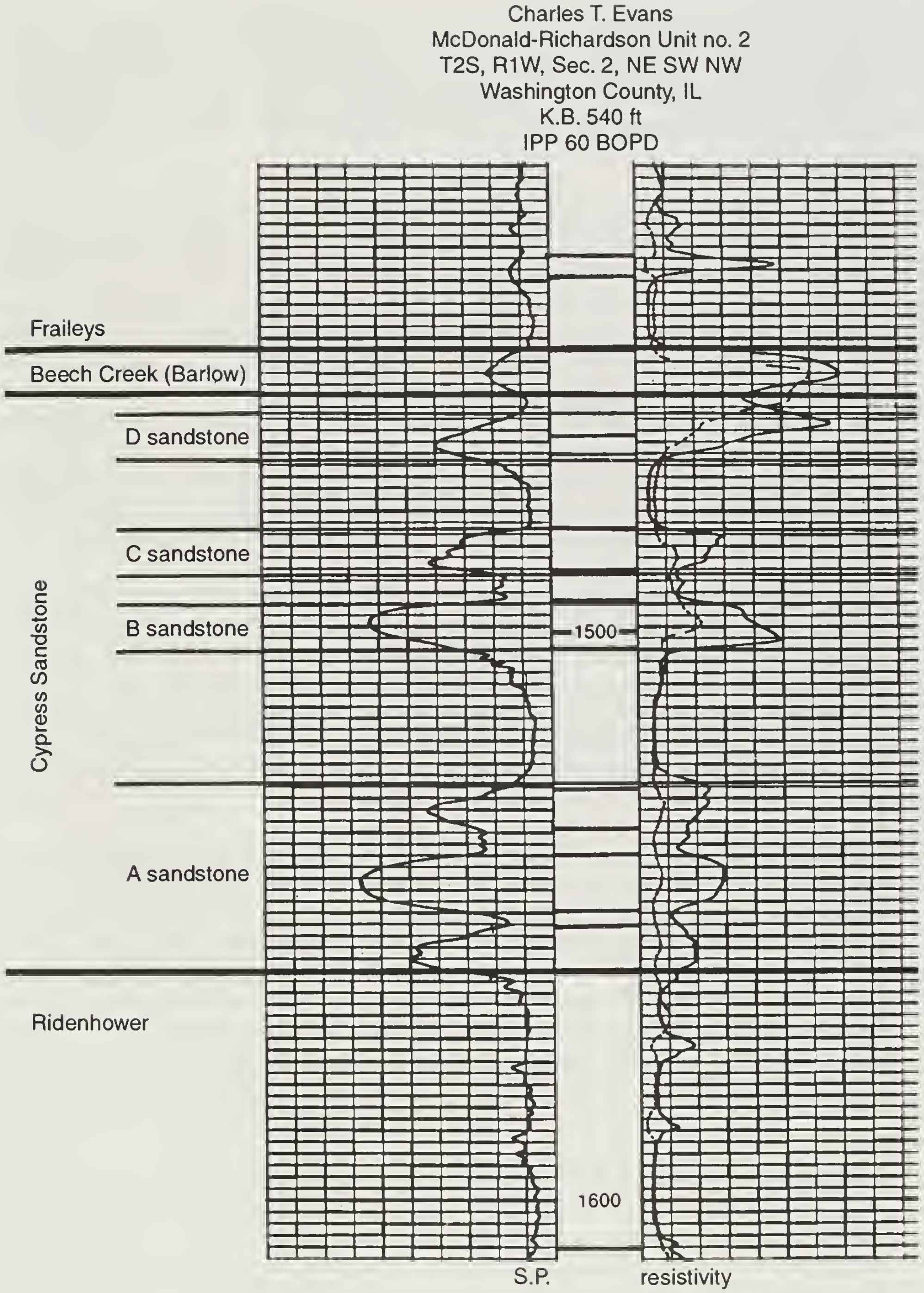


Figure 6 Type log of the Cypress Formation with divisions used for mapping in this study. The Cypress B and C sandstones are the principal reservoirs at Richview Field. The Cypress D sandstone is a less extensive reservoir.

prolific reservoirs in the field, are lenticular and stacked like the Cypress sandstones at Tamaroa and Tamaroa South Fields (Grube 1992). Thin, lenticular Cypress D sandstones that occur directly beneath the Barlow limestone are, in general, marginally productive.

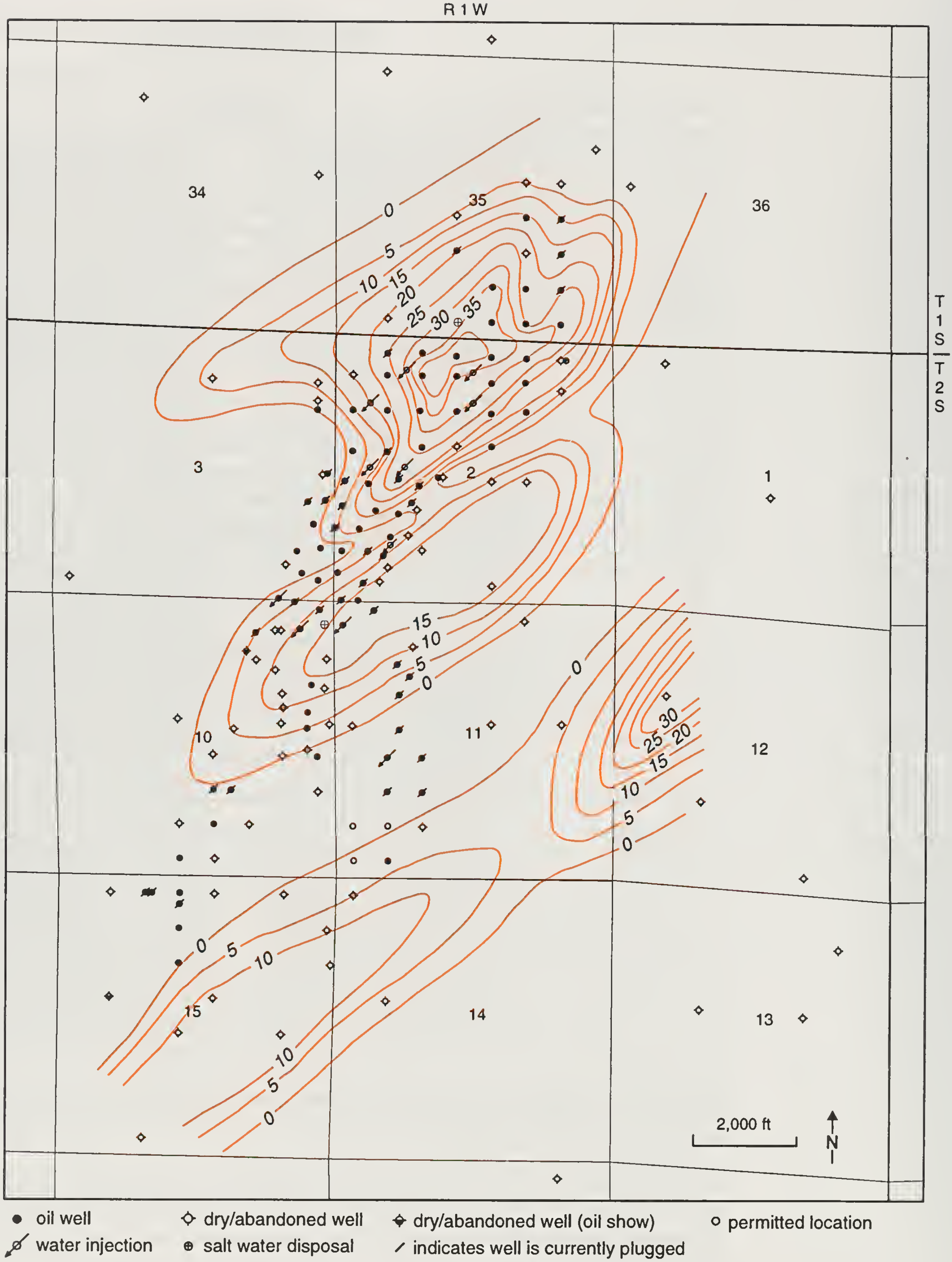


Figure 7 Net thickness map of the Cypress A sandstone that is greater than 50% clean. Contour interval is 5 feet.

Isopach maps were constructed for each of the four sandstones to determine their geometry and their spatial relationships to each other; the geometry and spatial relationships are useful for determining environments of depositionand for identifying reservoir compartments. The maps were also used to calculate the volumetrics of the field.

Cypress A sandstone A thickness map of 50% clean sandstone in the Cypress A interval (fig. 7) shows sandstone bodies up to 40 feet thick trending northeast–southwest in the study area. For each particular well, a 50% clean sandstone refers to that portion of a sandstone response on the SP curve that deflects to the left of a point that is one-half the distance between the shale baseline (0% clean sandstone) and a sandstone with the greatest amount of SP deflection (100% clean sandstone). The shale baseline for the Cypress was established by using the consistent flat-line response of the Fraileys Shale. The 100% clean sandstone SP response was calibrated using the Tar Springs Sandstone or a Cypress sandstone with the greatest amount of SP deflection. A 100% clean Cypress sandstone in the Richview area commonly displays a negative 100–120 millivolt deflection from the shale baseline. A 50% or greater clean sandstone cutoff was used to delimit reservoir-quality sandstone.

The Cypress A sandstone appears to be present in most of the northern part of the field but absent in the very southern part of the field. The SP log character shows a variety of Cypress A sandstone responses throughout the study area, including multiple benches, fining upward, coarsening upward, and blocky. Log characteristics and core analysis of this sandstone indicate that the Cypress A sandstone is of reservoir quality. The Cypress A sandstone is productive in the northern part of the field where the sandstone is structurally high enough to extend above the oil–water contact.

Cypress B and C sandstones The Cypress B and C sandstones form the primary reservoirs in Richview Field. A shaley interval, ranging in thickness from less than 1 foot to 4 feet, commonly separates the Cypress B and C sandstones (fig. 6). This shaley interval decreases in thickness toward the middle of the field and becomes imperceptible on some logs (fig. 8). A shale interval, commonly 10 feet thick but ranging from less than 1 foot to 30 feet thick, separates the Cypress A sandstone from the overlying Cypress B sandstone. Drill cuttings from representative wells across the field commonly contain red and green to variegated mudstone beds near the top of the shale between the Cypress A and B sandstones. Rare coal cuttings are also observed in this shale interval.

A 50% clean sandstone thickness map of the Cypress B interval shows a principal sandstone body with two southern offset lenses (fig. 9). These sandstone bodies trend northeast–southwest and measure over 3 miles long and ⅓ to ½ mile wide. The Cypress B sandstone attains a thickness of approximately 25 feet along the central part of the main pool and is less than 10 feet thick in the two southern offsets.

Production from the Cypress B sandstone is restricted to the structurally higher portion of the field. An oil–water contact at –963 feet subsea (963 ft below sea level) is common to all productive sandstones throughout the field. For the Cypress B sandstone, the oil–water contact lies approximately halfway between the –910 and –920 foot contours on the Barlow structure map (fig. 3). The southwestern offset field in Sections 10 and 15 appears to produce entirely from the Cypress B sandstone.

A 50% clean sandstone thickness map of the Cypress C (fig.10) interval shows this sandstone coincides geographically with the underlying Cypress B sandstone

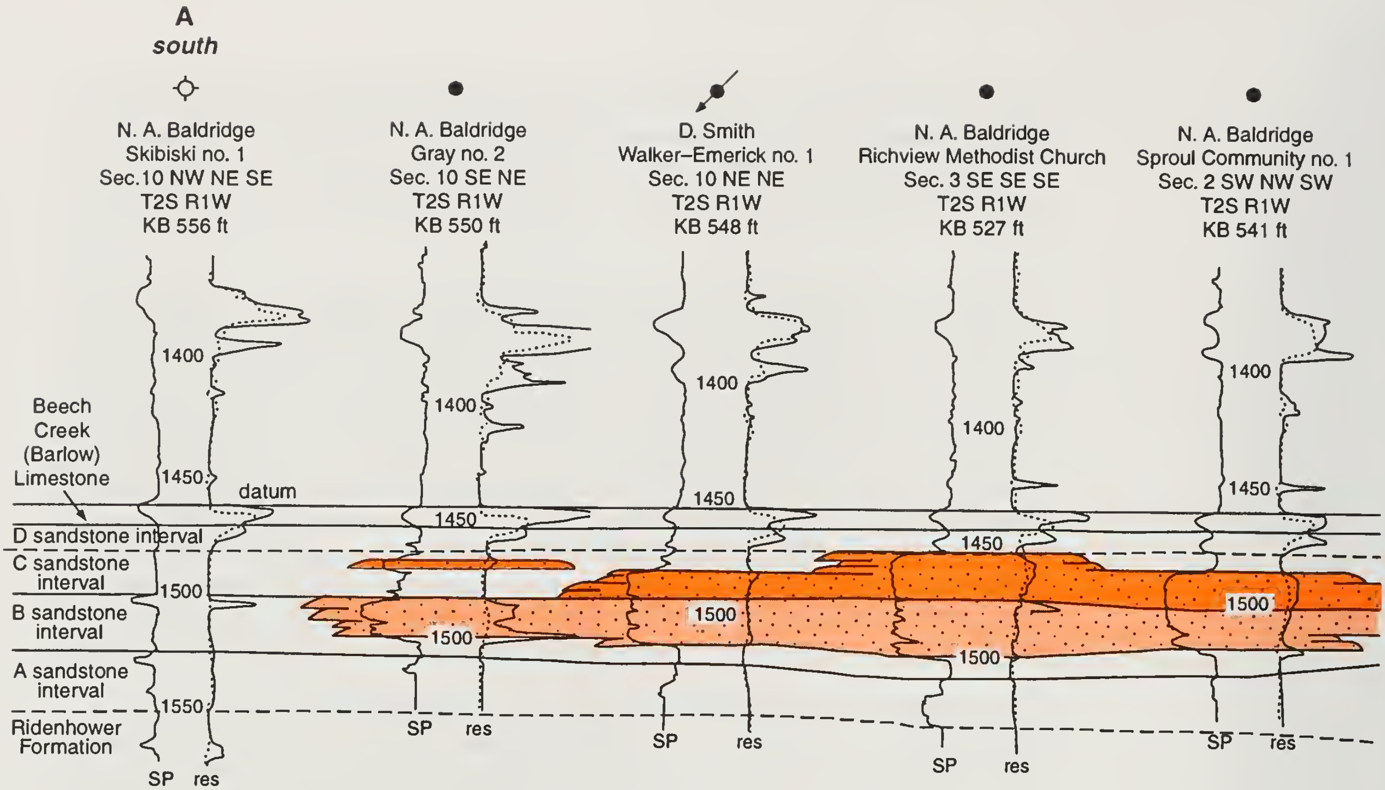
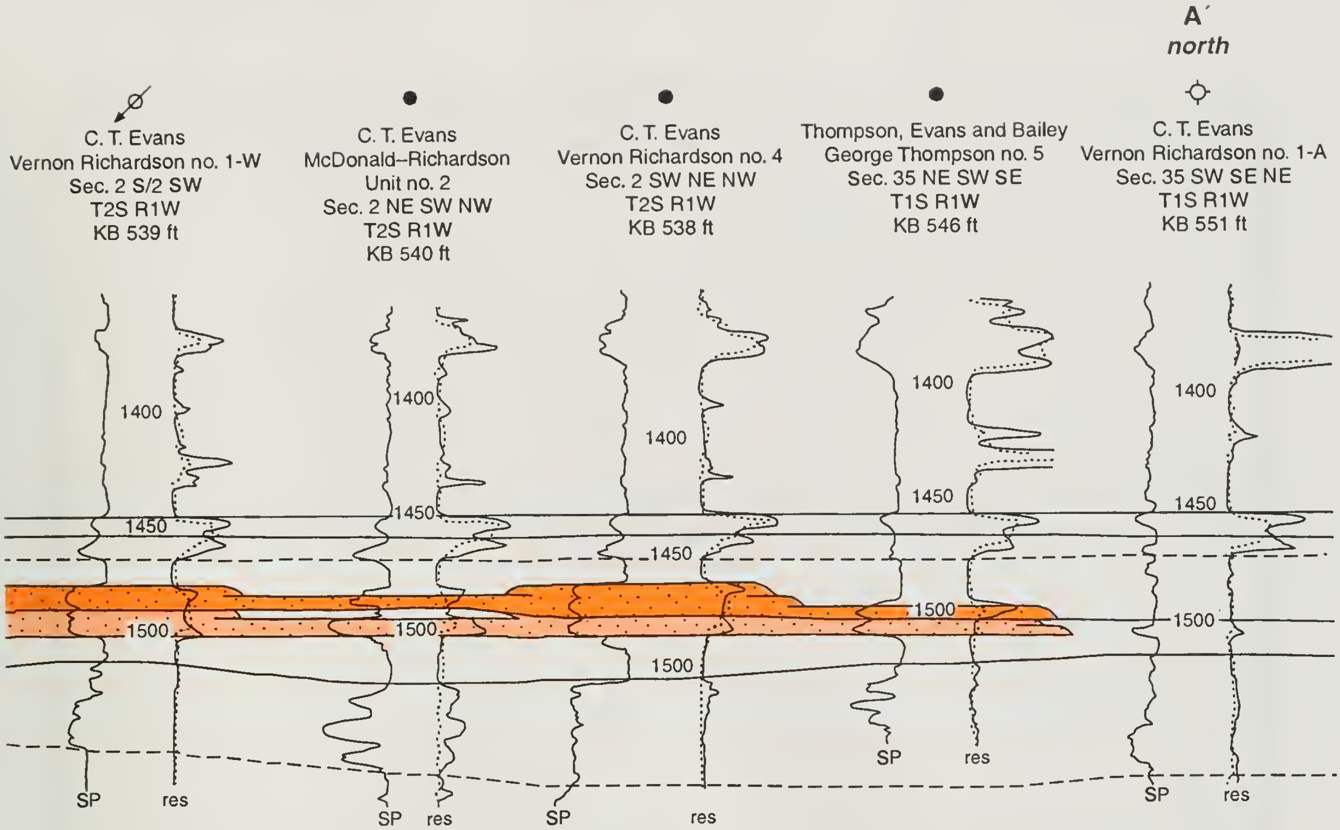


Figure 8 Stratigraphic cross section, A–A′, showing the widespread shaley interval that separates the Cypress B and C sandstones. The Cypress C sandstone increases in thickness by the addition of stacked pods or lenses of sandstone. The Cypress B sandstone has similar characteristics. Stacked lenses appear to form vertically continuous sandstones more than 20 feet thick, but an examination of the SP traces show subtle to obvious positive deflections at the boundaries of the lenses. The SP deflections indicate that the lenses are commonly separated by very thin impermeable beds that compartmentalize and reduce the fluid flow capability of the Cypress B and C sandstones. Line of this cross section is shown on figure 9.

(fig. 9). Unlike the Cypress B sandstone, the Cypress C sandstone has no offset lenses. Thickness of this sandstone is greatest along the central part and reaches a maximum thickness of 20 feet. The Cypress C sandstone increases in thickness from north to south by the addition of discrete, stacked or shingled pods of sandstone (fig. 8). This stacking characteristic indicates migration or aggradation during deposition from north to south.

The Cypress C sandstone lies structurally above the oil–water contact across the entire field and therefore produces where it becomes reservoir quality. The Cypress C sandstone continues northeast of the field, where it dips below the oil–water contact as it plunges down the Du Quoin Monocline along the east edge of Section 35, T1S, R1W. The continuity of the Cypress C sandstone and its position above the oil–water contact are favorable for secondary recovery, particularly in areas where this sandstone is separated from underlying water-bearing zones.

Cypress D sandstone The Cypress D sandstone, referred to as the "Notch" in parts of the Illinois Basin because of the way it lies directly beneath the Barlow limestone, is separated from the underlying Cypress C interval by a shale. Drill cuttings of this shale also display variegated beds and rare coal cuttings. The 50% clean sandstone thickness map of the Cypress D interval shows multiple lenticular sandstones up to 6 feet thick that trend northeast–southwest (fig. 11). The trend and location of these sandstones coincide with the underlying Cypress B and C sandstones. Low SP log responses for the Cypress D sandstone throughout the field indicate that the average permeability of this sandstone is less than the average permeability of the Cypress A, B, or C sandstones. Core reports from four wells in the northwest



quarter of Section 2 confirm that the Cypress D sandstone has abundant shale partings and wavy shale laminations. Average porosity and permeability values for the Cypress D sandstone in these cores are smaller than the average values for the Cypress B and C sandstones in cores from elsewhere in the field.

Production from the Cypress D sandstone occurs in the southeastern pool, Section 11, T2S, R1W, where it is the only reservoir and, therefore, the primary objective. Scattered Cypress D production occurs in the central part of the main pool, in Sections 2 and 3, T2S, R1W.

Structure

The major structural features related to Richview Field were described on page 5. An examination of the Barlow structure map (fig. 3) shows no significant four-way closure within the study area. The field lies along a well-defined structural saddle between the Irvington Anticline to the north and the structural extension of that anticline to the south. Production is associated with the draping of lenticular reservoir sandstone bodies onto and across the structural saddle.

The structural trend of the saddle sharply changes direction starting approximately at the center of Section 2 (figs. 3 and 4). The saddle trends northeast–southwest in the southern part of the field and trends northwest–southeast in the northern part of the field. The thickness and depositional trends of the Cypress B, C, and D sandstones and the Barlow limestone all change at this structural bend, which indicates that their deposition may have been influenced by a preexisting tectonic feature. The change of structural trend is likely the result of deformation of the sedimentary section overlying basement fault blocks. The stratigraphic changes that occur in the Cypress B, C, D and Barlow intervals in the north half of Section 2 may have been induced by recurrent movement of the fault blocks during or preceding deposition. A surface expression of a fault or fracture zone along a basement block boundary

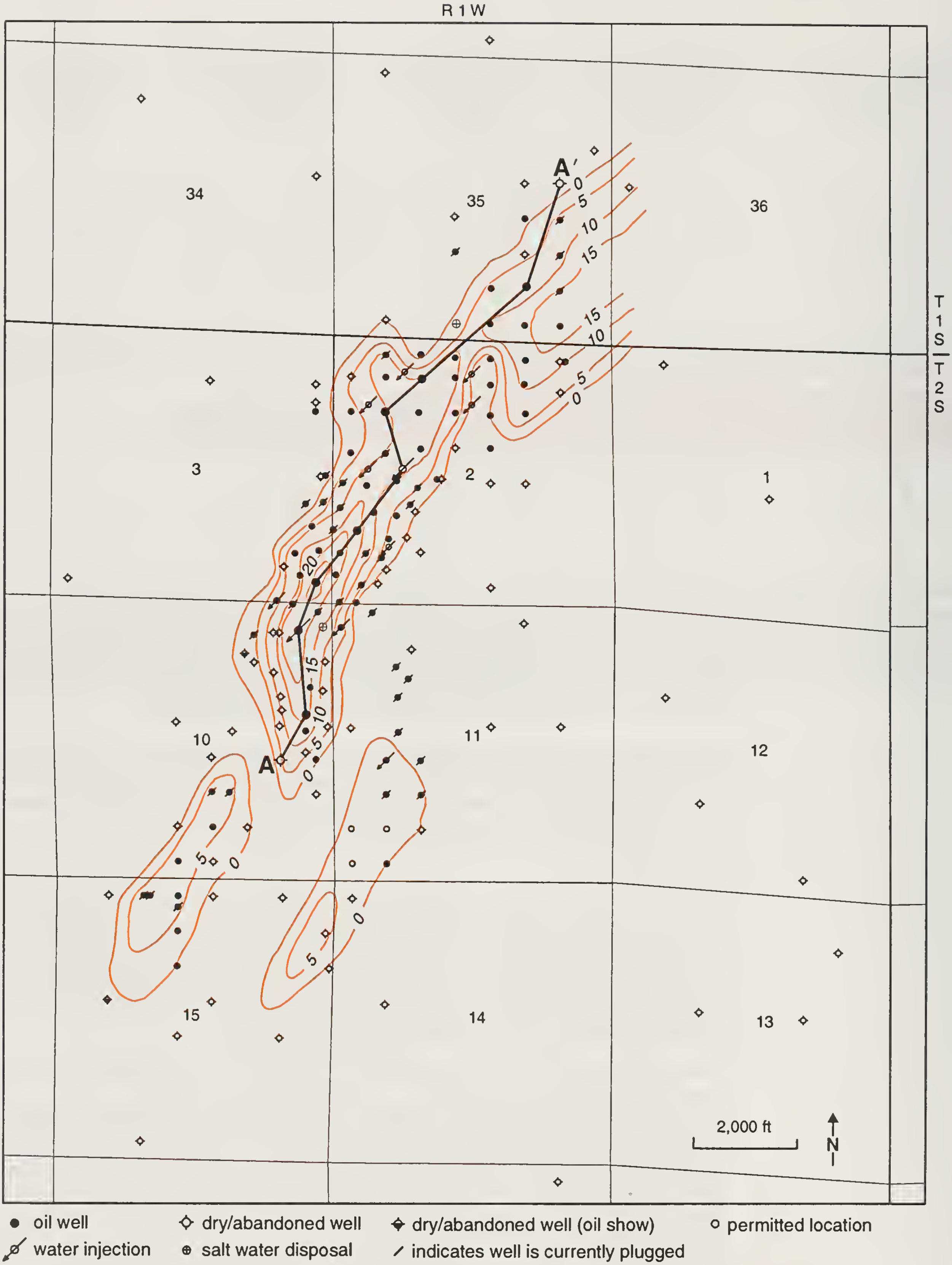
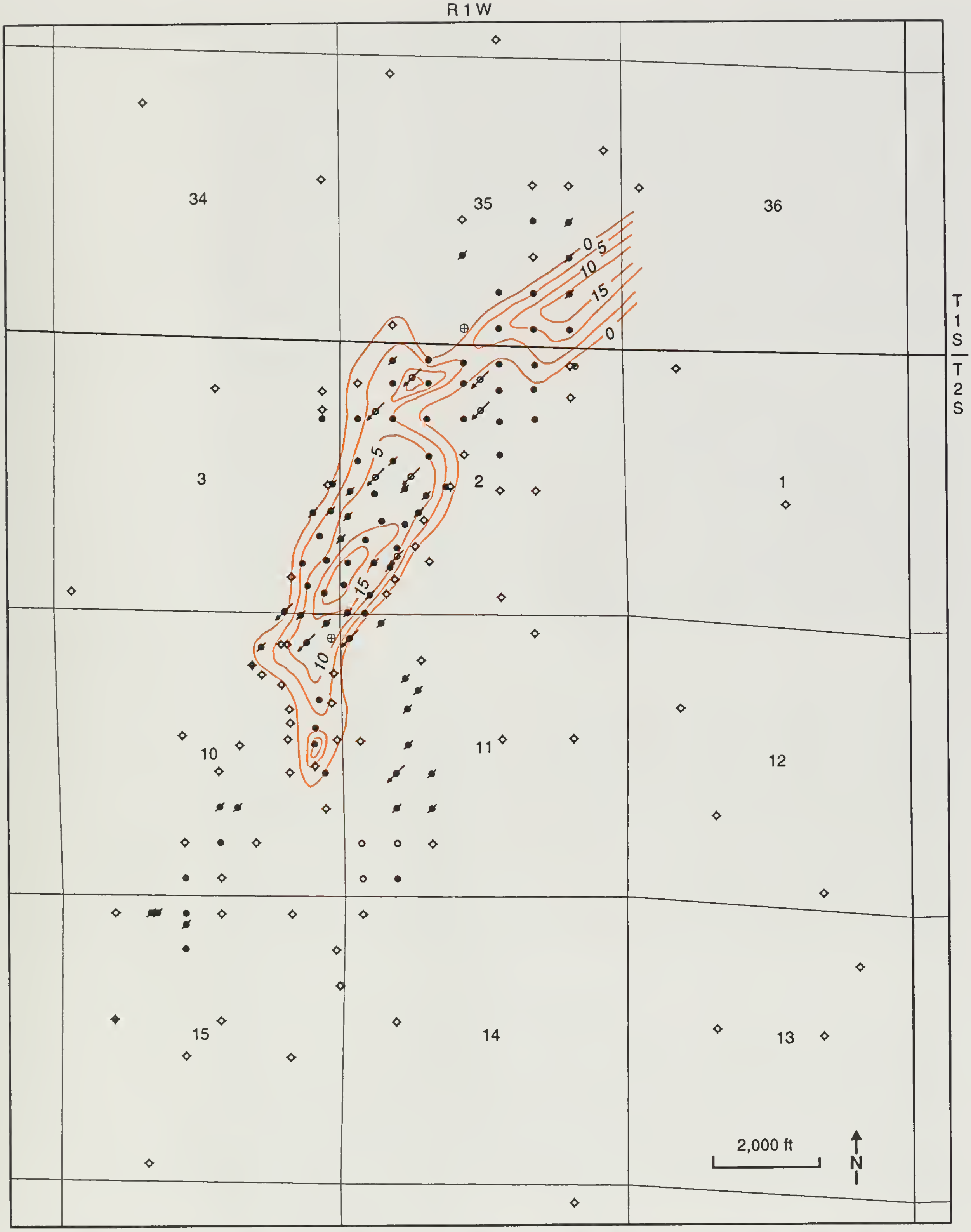


Figure 9 Net thickness map of the Cypress B sandstone that is greater than 50% clean. Contour interval is 5 feet. Location of cross section A–A′ is shown.



● oil well ◇ dry/abandoned well ◆ dry/abandoned well (oil show) ○ permitted location
water injection ⊕ salt water disposal / indicates well is currently plugged

Figure 10 Net thickness map of the Cypress C sandstone that is greater than 50% clean. Contour interval is 5 feet.

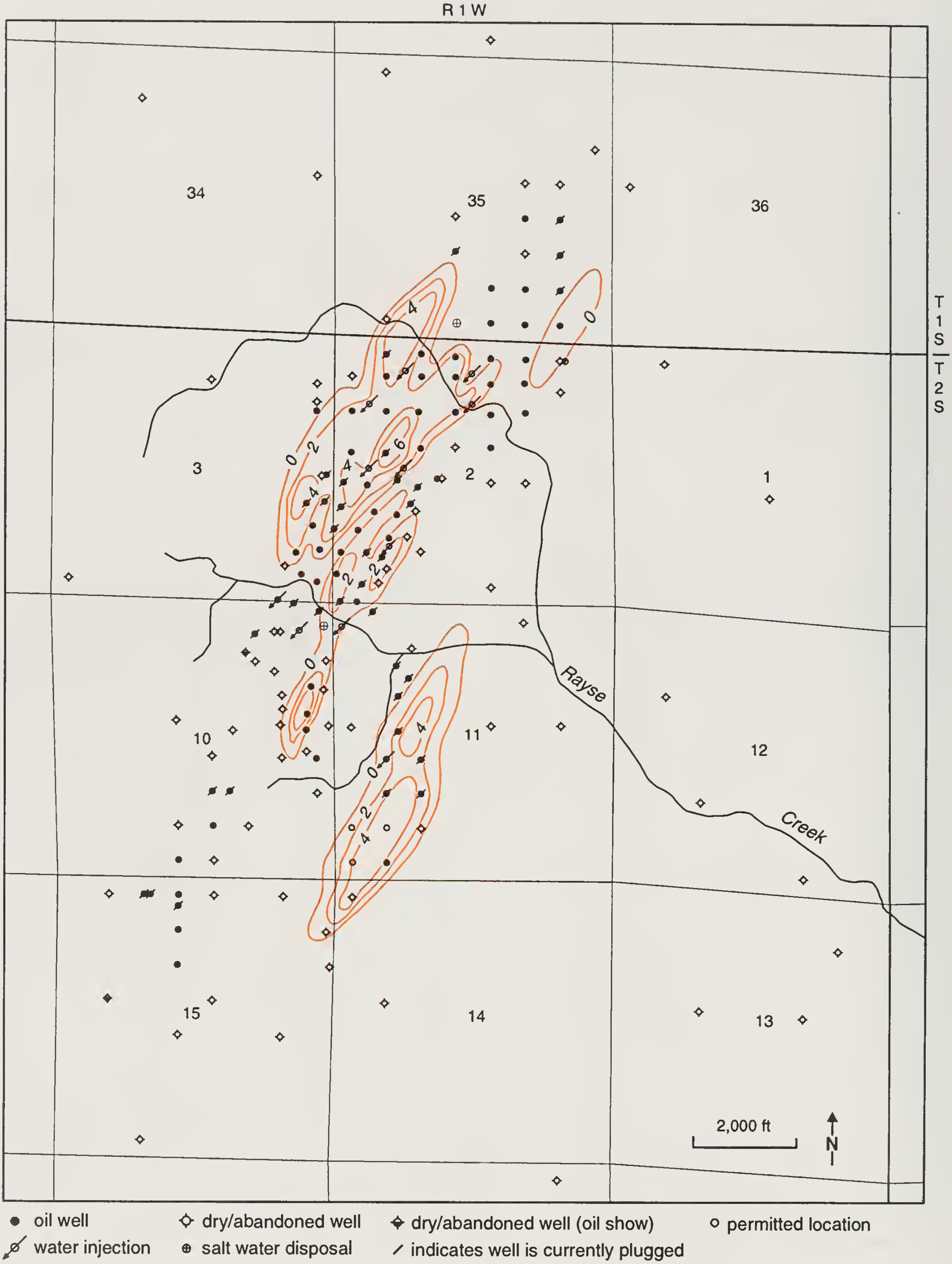


Figure 11 Net thickness map of the Cypress D sandstone showing multiple, lenticular sandstones trending northeast–southwest. Contour interval is 2 feet.

may be reflected in the drainage pattern of Rayse Creek, particularly in the north half of Section 2 where the creek parallels the northwest–southeast trend of the Irvington Anticline. Rayse Creek, which generally flows southeast from the Richview area, branches to the north in the northeast quarter of Section 11 and then resumes a northwest–southeast trend through the north half of Section 2 (fig. 11). The portion of the creek in the north half of Section 2 coincides with the area where the Cypress B and C sandstones become thin and narrow, the Cypress D sandstone truncates, and the Barlow thins and thickens randomly (fig. 12). The trend and location of Rayse Creek coincident with the change in stratigraphy in multiple horizons, the change in trend of the structural saddle, and the higher cumulative production from the part of the field near the creek indicate that a fault or fracture zone may cross the north half of Section 2. A faulted or fractured zone not only may have enhanced production in this area, but may also be the conduit that allowed hydrocarbons to migrate into and charge the Richview Field reservoirs.

Although structural closure is not observed on the Barlow limestone, the limestone thins at a location coincident with the main part of the field. Thickness of the limestone ranges from 8 to 29 feet within the study area (fig. 12). The Barlow also thins over Cypress sandstones at the Tamaroa and Tamaroa South Fields (Grube 1992). Thinning of the Barlow in both the Tamaroa and Richview Fields appears to be the result of compensating deposition. Where the Cypress consists predominantly of sandstones, the Barlow is thin; and where the Cypress is made up predominantly of shale, the Barlow is thick. The greater compaction of the shales relative to the sandstones in the Cypress Formation was compensated for during the deposition of the Barlow limestone.

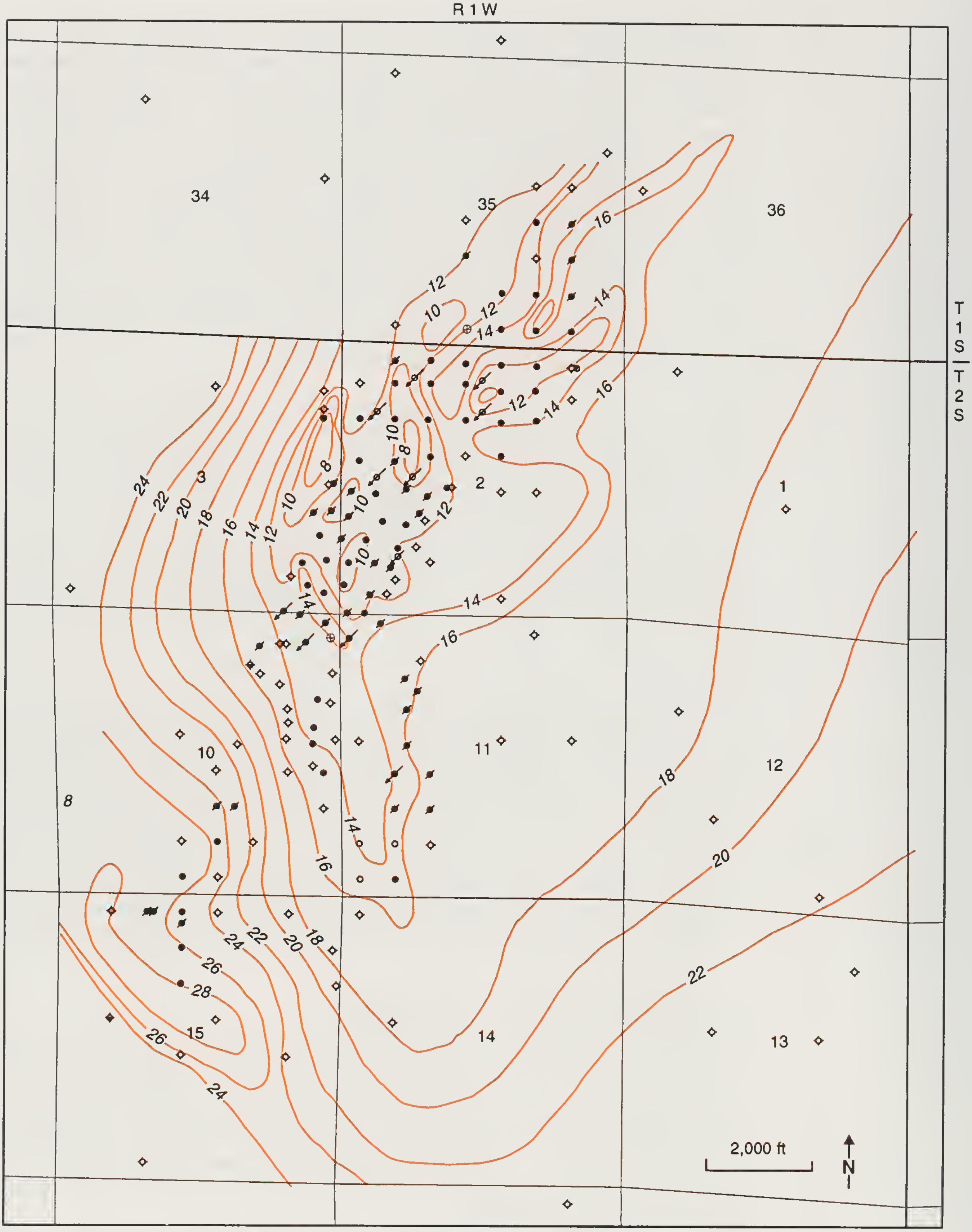
Trap Type

The trapping mechanism at Richview Field is a combination of structure and stratigraphy. Oil at Richview Field is not trapped within a closed structure. The reservoirs at Richview are lenticular sandstones that are encased in shale. Oil is trapped at the updip pinchout of the lenticular sandstones, along the flank of the structural fold (saddle), or where the sandstones drape across the crest of the fold. The field has a uniform oil–water contact, which allows sandstones above that contact on the flank of the structure to be productive. The shales that overlie the sandstones and most likely underlie the Barlow provide the permeability seal. The fact that a uniform oil–water contact exists throughout the field indicates either that oil has migrated through fractures in the shale between the Cypress B and C sandstones or that the sandstones are connected locally.

Reservoir Lithology and Petrology

Drill cuttings for approximately 20% of the 150 wells in and within ½ mile of Richview Field were available for lithologic analysis. Core analysis reports for the Cypress Formation from 11 wells in Section 35, T1S, R1W, and Section 2, T2S, R1W, provided petrophysical and lithologic data. Small-diameter plugs taken from a core of the Cypress C and D sandstones of the Cecil Newcomb et al. No. 2 well (NW SW NW, Section 2) were the only source for cored rock samples available for use in thin section, scanning electron microscope (SEM) with energy dispersive X-ray (EDX), and X-ray diffraction analyses.

Drill cuttings and core plugs of reservoir rock from all intervals are lithologically similar and are composed of very light gray to white, moderately well sorted, fine to very fine grained sandstone; where this sandstone is the reservoir, it is oil stained light brown. The Cypress B and C reservoir sandstones are very clean where the SP log



● oil well ◇ dry/abandoned well ◆ dry/abandoned well (oil show) ○ permitted location

water injection ⊕ salt water disposal / indicates well is currently plugged

Figure 12 Thickness map of the Beech Creek (Barlow) Limestone. Contour interval is 2 feet. The Cypress consists predominantly of sandstones where the Barlow is thin.

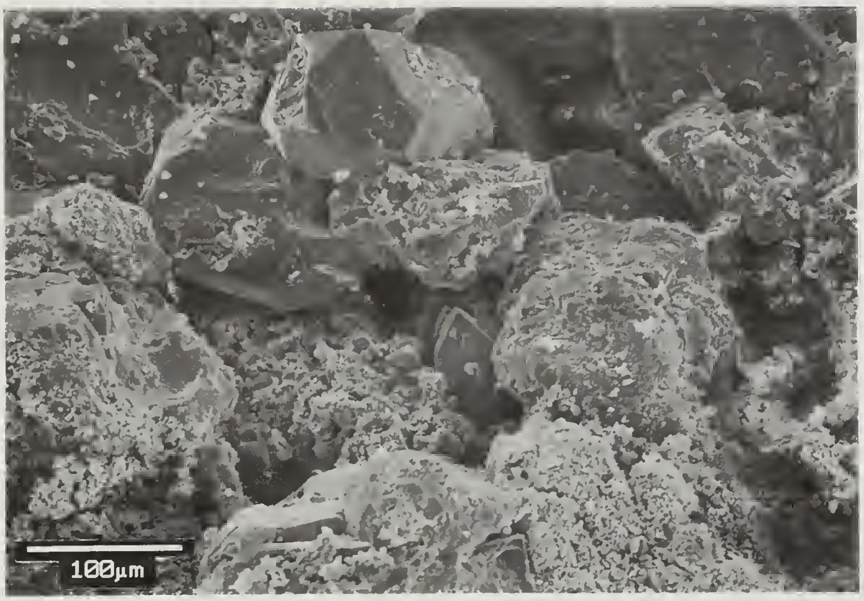


Figure 13 SEM photomicrograph shows angular sand grains resulting from quartz overgrowths. Several pore throats in the center of the photomicrograph are restricted by overgrowths. In the lower part of the image, clay minerals coat the sand grains and appear to retard quartz overgrowths. Sample is from the Cypress C sandstone reservoir of the Droege Unit No. 2 (1,505.5 feet).

shows at least a 75% clean deflection. Silica cement is pervasive throughout the sandstones and is the dominant cement in the reservoirs (fig. 13). Thin section and X-ray diffraction analyses from the Droege well core plugs show that the petrographic characteristics of the Cypress C sandstone and the Cypress D sandstone were all generally similar. The analyses indicate that the sandstones are relatively clean. Quartz accounts for approximately 90% of the samples; feldspar, clay minerals, calcite, dolomite, chert, mica, and traces of heavy minerals make up the remaining 10% (table 1).

Table 1 Weight percentages of mineral constituents taken from bulk pack (total mineral) X-ray diffraction analyses of six Droege Unit No. 2 core plugs.

	Depth (ft)					
	1,484.5	1,504.5	1,505.5	1,507.5	1,510.5	1,512.5
	Weight (%)					
Clay	5	4	7	1	5	6
Illite	0.2	2.3	1.8	0	0.3	1.1
Illite/smectite	0.2	1.2	1.4	0	0.1	0.8
Kaolinite	4.7	0.3	3.6	1.2	4.1	3.9
Quartz	83	93	88	99	90	80
K-feldspar	0	0	0	0	0.7	1.4
(Na-Ca) feldspar	2.6	0.9	1.6	tr	2.0	3.0
Calcite	2.9	2.0	3.1	tr	1.3	10.0
Dolomite	6.2	0	0	0	1.3	0

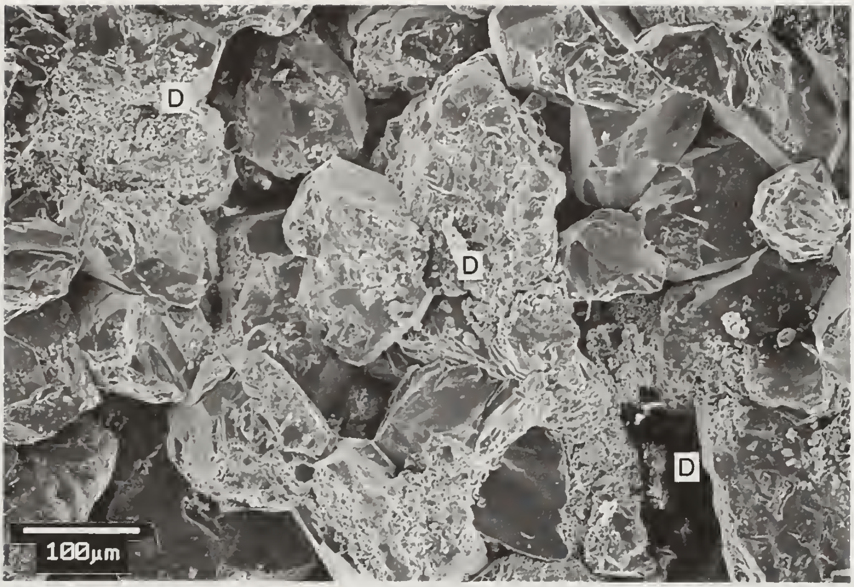


Figure 14 SEM photomicrograph shows sites where feldspar grains have undergone near-total to total dissolution (D). Common to these sites is a concentration of diagenetic clay minerals. Kaolinite is the dominant clay mineral in this image. Pore space between the quartz grains and the size of pore throats are restricted by quartz overgrowths. Sample is from the Cypress C sandstone reservoir of the Droege Unit No. 2 (1,510 feet).

Fine grained quartz sand having pervasive quartz overgrowths dominates these samples. The subangular to angular appearance of the grains results from the subhedral to euhedral crystal habit of the quartz overgrowths. Visible infilling by quartz overgrowths along grain contacts has decreased the pore space and pore throat size, which thereby decreases porosity and permeability (fig. 13). Quartz overgrowths may also have increased the tortuosity of flow paths within the sandstones, which can reduce hydrocarbon flow rates through the reservoir.

Secondary porosity has been created by the dissolution of feldspar grains. Partial to complete dissolution of fine sized feldspar grains is clearly visible in SEM images (fig. 14) and in thin sections.

Calcite, mica, and heavy minerals are minor constituents of the reservoir rock. In the available samples, calcite occurs as a scattered to rare, patchy cement that usually is of little consequence to oil production. Calcite cement patches rarely incorporate more than a few sand grains and may be fossil induced like the syntaxial cements associated with echinoderm fragments observed by Whitaker and Finley (1992, plate 4). Fine to very fine, rounded, heavy mineral grains are scattered to rare. Overall, mica grains are rare but do occur disseminated throughout the sandstones or concentrated along shale laminations.

Carbonaceous flakes are commonly observed in drill cuttings from particular horizons in the field area. The carbonaceous material is in the basal Cypress D and B sandstones and in the upper Cypress C and upper Cypress A sandstones. The shales between the Cypress A and B sandstones and between the Cypress C and D sandstones also contain carbonaceous flakes and rare to scattered coal cuttings.

Core descriptions from core analysis reports and observations of core plugs from the Cecil Newcomb et al. No. 2 indicate that thin, wispy, wavy shale laminations are common in some parts of the reservoir sandstones. Thin sections show paper-thin laminations that are discontinuous; their appearance suggests they probably were deposited cyclically. Scattered, flat clay clasts were also observed in some beds in the cores and core plugs. Calcareous beds, typically thinner than 2 feet, occur in some cores at the base of the Cypress B sandstone, in the uppermost part of the Cypress C sandstone, or both, and can be distinguished on logs by high resistivity spikes with a correspondingly low SP (fig. 8, No.1 Sproul Community and No. 2 Gray wells). Fossil fragments are common in these beds. Some of the sandstones include thin limestone beds within the sandstones.

Depositional Environments

Interpretation of the depositional environments of the Cypress Formation requires discussing many aspects of shallow marine deposition, including the nature of tidal and wave energies, shelf gradient, subsidence rates versus rates of deposition in relation to accommodation space, and the effects of variations in sea level. While it is beyond the scope of this publication to discuss these aspects in detail, some basic facts can be established from which a simple depositional model can be developed. The classical interpretation by Swann (1963) of a southwestward-prograding delta that flooded siliclastic materials into the Ridenhower sea can be applied as a basic model for deposition of the Cypress Formation.

It is generally accepted that water depths throughout the area were not great and probably never greatly exceeded wave base. That the thickness of the Cypress Formation exceeds approximately 110 feet only in areas where it appears to be incised into the underlying Ridenhower, facies changes that are widespread and very rapid, and the presence of subaerial indicators (including coals and variegated beds) in the upper one-third of the formation support the interpretation of shallow water deposition interrupted by periods of subaerial exposure. These characteristics also indicate that the Cypress delta(s) deposited sediments onto a low-gradient shelf that had very little accommodation space.

Sedimentary features indicate that tidal processes more than storm processes controlled Cypress deposition. Thick beds of sandstone that contain wispy, wavy, discontinuous shale laminations or even grade to flaser beds predominate over scattered, thin beds of subhorizontal or cross-laminated sandstones. Sandstone bodies, particularly in the upper Cypress, are lenticular, 1–2 miles long, and less than ½ mile wide. The lenses commonly form a series of subparallel ridges that trend northeast–southwest. These ridges are comprised of thin discrete bodies, generally 3–10 feet thick, that stack and appear to coalesce on electric logs. Sedimentary features and sandstone body geometries are not those generally found in river-dominated (lobate) or wave-dominated (cuspate) deltaic depositional systems. The lenticular, stacked, and aligned sandstone bodies of the Richview Field are most analogous to the linear tidal ridges that form in the high-tidal-range-dominated environments of the Ord River Delta of northern Australia (Wright et al. 1975) or the Gulf of Korea portion of the Yellow Sea (Off 1963). In this model, then, the highly variable Cypress A sandstone bodies of the lower Cypress in the Richview area represent progradational (regressive) deposits of a tidally dominated delta system capped by tidal-flat siltstones, mudstones, marsh deposits, and thin coals. Variegated beds in this capping horizon indicate subaerial exposure. The beds may have formed as a result of the oxidation or reduction reactions that occur at the groundwater–air interface, or they may represent in some places a remnant soil horizon.

The Cypress B and C sandstones appear to be tidal-ridge deposits that formed during a subsequent, short-lived transgressive pulse that flooded and embayed the earlier delta systems. Variegated beds and minor coals that lie between the Cypress C and D sandstones indicate another period of subaerial influence that followed deposition of the Cypress C sandstone. A final transgressive pulse that marks the end of siliciclastic deposition within the Cypress is represented by the Cypress D interval. Because lithologic characteristics of the Cypress D sandstones and the geometry and alignment of the Cypress D sandstone bodies are similar to those of the Cypress B and C sandstones, the Cypress D sands may also have been deposited as tidal ridges. Immediately overlying the sediments of the Cypress D interval are the carbonates of the widespread Barlow limestone.

Diagenesis

Petrographic analyses of the reservoir samples show that three diagenetic alterations significantly modified the Richview Field reservoir rock. These alterations include (1) precipitation of quartz overgrowths, (2) dissolution of feldspar, and (3) precipitation of the clay minerals kaolinite, chlorite, and illite/smectite.

Precipitation of quartz overgrowths and quartz cement occurred early in the diagenetic events recorded in the Cypress reservoirs. Quartz precipitation in the Cypress B and C sandstones was widespread and, for the most part, unimpeded by detrital clay within the clean, reservoir-quality sandstones. Detrital clay was probably winnowed by currents during deposition of these sands, which made them susceptible to diagenetic alteration. Where quartz grains are in contact with detrital clay or diagenetic clay minerals, silica precipitation appears to have been impeded (fig. 13).

Feldspar dissolution not only created secondary porosity but also may have enriched the brine waters with the aluminum and silica necessary for the precipitation of kaolinite, chlorite, illite/smectite, and quartz overgrowths. Various stages of feldspar alteration occur in the upper Cypress sandstones at Richview. Partial and presumed total dissolution are pervasive in the clean reservoir sandstones. Voids and cavities formed by the dissolved feldspar grains are common. The remaining feldspar is mostly sodium-rich plagioclase. A trace of potassium feldspar also is present. The calcium type plagioclase was probably more extensively altered and dissolved than the other types of feldspar because it is generally less stable under normal reservoir conditions.

Three separate methods were used to analyze the reservoir clay minerals: (1) thin section, (2) X-ray diffraction bulk pack, and (3) SEM with an energy dispersive X-ray analyzer (EDX). Although the quantity of clay minerals in the clean reservoir samples appears to be less than 4% of the sample (table 1), knowledge of the types of clay minerals present in the reservoirs and their specific location is crucial for optimal development of the reservoirs. Thin section analysis revealed relatively few clay-filled pores in the clean portion of the reservoir. Patchy, clay-filled areas and thinly laminated, bedded clays, probably both detrital and diagenetic in origin, were observed as minor constituents within the cleaner reservoir samples. The diagenetic clay minerals observed by SEM are concentrated near the dissolved feldspar grains where they form a delicate veneer on the surface of quartz grains. Otherwise, the clay minerals are very spotty and rarely coat an entire grain. Both diagenetic kaolinite and chlorite were observed with the SEM in samples of the clean reservoir sandstone. Illite and mixed-layered illite/smectite and kaolinite were found in the bulk x-ray diffraction samples of the reservoir sandstone (table 1). Kaolinite (fig. 15) and chlorite (fig. 16), largely the iron-rich variety, are present in the samples according to SEM-EDX observations, although bulk X-ray diffraction analysis does not indi-

Figure 15 SEM photomicrograph shows kaolinite crystals on a quartz overgrowth substrate. The kaolinite booklets are loosely bound to the quartz grain. The sample is from the Cypress C sandstone reservoir of the Droege Unit No. 2 (1,505 feet).

cate the presence of chlorite (table 1). Although the detrital clay laminations affect the reservoir by decreasing vertical permeability, the dispersed, diagenetic clay minerals that veneer quartz grains present a large surface area to passing fluids and thus have a greater potential than the detrital clay to reduce reservoir permeability.

Petrophysical and Stratigraphic Characteristics That Influence Reservoir Quality

Post-depositional processes such as silica cementation and clay mineral precipitation have reduced the porosity and permeability of the rocks at Richview Field. Permeability is a function of pore throat size. Reduction of the pore throat size, which increases flow resistance due to flow path tortuosity, may help to explain the low production rates and longevity of many Cypress wells. Although primary porosity has been significantly reduced by silica precipitation, secondary porosity of up to several percent has been created by the dissolution of feldspar grains, which yields a net porosity of approximately 20%. While the post-depositional addition of clay minerals has only slightly reduced the porosity and permeability of the reservoir rocks, the susceptibility of these minerals to alteration by reaction to drilling, stimulation, or other fluids injected into the reservoir poses a very significant threat of permeability reduction. This problem is discussed on pages 30–31.

Core analysis reports of Cypress cores from 11 wells in Section 35, T1S, and Section 2, T2S, provided porosity and permeability analyses from 2 cores of the Cypress A sandstone, 9 cores of the Cypress B sandstone, 11 cores of the Cypress C sandstone, and 4 cores of the Cypress D sandstone. The core data indicate that within individual sandstones the permeability is more variable than the porosity. In general, porosity appears to be fairly constant, and increases slightly with increased permeability.

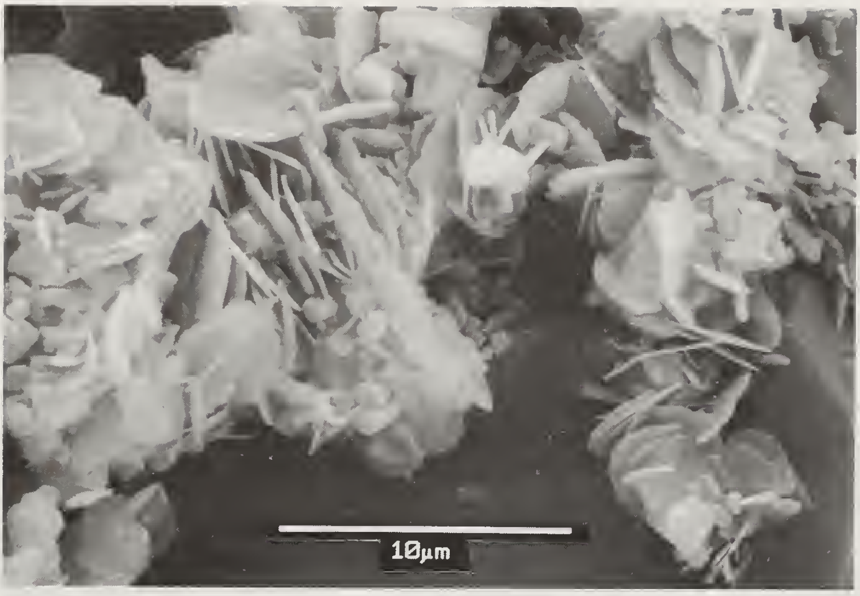


Figure 16 SEM photomicrograph shows iron-rich chlorite rosettes on a quartz grain. Blocky crystals of kaolinite are intermixed. The sample is from the Cypress C sandstone reservoir of the Droege Unit No. 2 (1,510 feet).

Permeability generally increases toward the middle of the individual sandstone beds. Measured porosity values for the Cypress A, B, and C sandstones that have high SP values range from 14% to 26% and average approximately 20%, whereas permeability values ranged from 3.5 to 752 millidarcies and average approximately 175 millidarcies. The SP deflection for sandstone with average porosity and permeability typically is more than 90% of the 100% clean sandstone response. Average measured porosities for three cores of reservoir-quality Cypress D sandstone are approximately 17%. A maximum permeability of 88 millidarcies was measured from the Cypress D sandstone cores, but the average permeability for the reservoir-quality Cypress D sandstones was 36 millidarcies.

Reservoir compartmentalization is widespread throughout the Cypress sandstones at Richview Field and occurs where discrete sandstone packages are stacked or shingled with thin shales or impermeable, shaley sandstone separating the packages. The shale break between the Cypress B and C sandstones, apparent in figs. 6 and 8, separates these sandstones into horizontal compartments. In parts of Richview Field, the intervening shale is not obvious on logs, and the B and C sandstones appear to form one sandstone body. Although the two sandstones may coalesce and actually form one compartment in a limited area, core analyses and core to log comparisons show that a thin shale or shaley sandstone commonly is present. In these cases, the SP or resistivity log failed to significantly react because of the thinness of the impermeable bed. The isolation of the two separate compartments is therefore maintained, although the conventional electric log interpretation suggests that only one compartment exists. In this situation, a secondary recovery program may fail to flood one of the two compartments because the more permeable compartment accepts the flood and is effectively drained, while the other compartment, which may not be permeable at the wellbore, is ineffectively drained. Small-scale heterogeneity is common and is created by the abundant shale laminations observed within the sandstones packages. Thin sections from this type of reservoir rock in other fields show isolated, oil-saturated compartments thinner than 1 centimeter that occur between wavy shale laminations. From a practical standpoint, the oil in these small-scale compartments is nonproducible.

Identification of Play

The upper Cypress sandstones that make up the reservoirs that constitute Richview Field were deposited as linear tidal ridges during a brief marine transgression. The northeast-trending lenticular sand ridges are encased in shale that forms the reservoir seal. Widespread, thin shale beds appear to separate and compartmentalize these stacked reservoirs.

Oil is trapped at Richview by a combination of structure and stratigraphy. Structural closure is not a factor in trapping this oil. Oil is trapped in the updip portions of lenticular sandstone bodies that drape across or are on the flank of a structural fold (saddle). The Richview structure is part of a subsidiary fold that formed along the uplifted side of the Du Quoin Monocline. Flexure and the resultant fracturing along the monocline probably facilitated oil migration and increased the oil productivity from Richview Field.

PRODUCTION CHARACTERISTICS

Production and Completion Procedures

Records indicate that rotary drive rigs were used to drill the wells at Richview Field. Mud systems utilized freshwater with gel, an additive that increases particle suspension. Most wells at Richview Field were drilled and cased through the reservoirs and then perforated with two to eight holes per foot. Completions commonly included hydraulic fracturing of the reservoir, usually using lease oil and sand. Fracture treatments using up to 20,000 gallons of fluid and 20,000 pounds of sand were administered, but most treatments used less than 5,000 gallons of fluid and 5,000 pounds of sand. Records show that many wells had natural completions without fracture stimulation. Acid was used mostly for mud and perforation cleanup. Calcite cement was apparently not a problem in these reservoirs; therefore, large-scale acid stimulation was unnecessary. Wells were pump produced from their initial completion; no flowing wells are recorded in the field.

Production and Waterflood Data

Production background for Richview Field was described on page 7. The decline curve (fig. 5) clearly shows the two-stage discovery and development of the field. Stage one, from 1946 through 1961, includes the initial discovery and production from the subsidiary Cypress B sandstone pool in Section 10. The second stage, starting in late 1961, includes the discovery and development of the main pool and the subsidiary pool in Section 11. Most of the field was developed by early 1963. A very steep decline in production from 1963 to 1966 approximates the natural decline of primary production as the reservoir's gas solution energy was rapidly depleted. Although an early flood was initiated in September of 1963, the effects are not immediately reflected on the curve. The effect of this early waterflood and a second flood initiated in October 1966 was a strong reversal of the decline in 1967. Restoration and maintenance of reservoir energy through waterflooding have proved to be very effective and are reflected in the flatness of the decline curve and the longevity of production. Ultimately, the maintenance of reservoir energy assisted in recovering significant amounts of incremental oil.

Five waterflood projects have been established in the main pool of Richview Field. Of the three not mentioned above, one was initiated in 1970 and the other two in

1971. Records show that the five waterflood projects included 12 injection wells, mostly converted producers, and 33 producers. The combined production and injection data for all five projects from inception of the waterfloods through 1985 indicate that 1.6 million barrels of oil and 12.3 million barrels of water were produced from the Cypress reservoirs and 22 million barrels of water were injected into the Cypress. Injection water was a combination of produced Cypress brine and brine from the overlying Tar Springs sandstone. Well head injection pressure records are available for only the Richview waterflood unit in the northern part of Section 2. Injection pressures in this waterflood range from approximately 50 to 1,000 psi but are commonly between 500 and 1,000 psi.

Reservoir Temperature, Pressure, and Drive

Drill stem tests and drilling mud measurements noted on electric logs are the only sources of reservoir pressure and temperature data for the field. The highest recorded drill stem test shut-in pressures are 475 to 480 psi at a depth of approximately 1,500 feet. The standard hydrostatic pressure gradient of 0.43 psi/foot is significantly greater than the 0.32 psi/foot value calculated from the drill stem test data. Several factors may contribute to the low reservoir pressure measurements: (1) Cypress reservoirs, in general, yield under-pressured values on drill stem tests, (2) formation damage from drilling fluids is very possible, and (3) the shut-in duration on the tests may have been too short, particularly if formation damage had occurred.

A maximum temperature of 96°F was measured from drilling mud during logging operations and is therefore the closest estimation of bottomhole temperature. Numerous well logs recorded measurements between 90° and 96°F.

Gas solution appears to be the primary drive mechanism at Richview, although no drill stem test reports recorded gas to the surface and most tests recovered low amounts of gas. That the reservoirs are encased in shale and that waterflooding was initiated early in the production history indicate water was not the energy source in the field.

Oil Characteristics

Oil samples were collected for gravity and viscosity analysis in 1992 from the McDonald-Richardson No. 2, SW NW, Section 2, and the Thompson No. 7, NE SE, Section 35. Gravity values for the two wells were similar, 37.5 and 37.3 degrees API at 60°F, as were the viscosity values, 4.9 and 4.7 cp at 73°F, respectively. The Thompson No. 7 is an anomalous well; it produces from the Cypress A sandstone, whereas the McDonald-Richardson No. 2 produces from the Cypress B and C sandstones. Records for the Richview waterflood unit in the northern part of the field showed values similar to those above: 39 degrees API gravity at 60°F and a viscosity of 3.3 cp at 84°F. Geochemical analyses of the oils and brines from the Thompson No. 7 and three other wells in the field are given in Appendix A.

Water Characteristics

Reservoir brine samples were collected simultaneously with the oil samples from the four wells used for oil geochemical analysis. Brine geochemical analyses (see Appendix A) include the measurement of Eh, pH, brine resistivity, and quantity of anions and cations. Samples from the Weisbecher Community No. 1, SW SW, Section 2, and the Edwards waterflood unit No. 1, SE SE, Section 3, may contain commingled waterflood brines consisting of Tar Springs and reinjected Cypress brine and, therefore, should not be considered as native Cypress brine data. The sample from the Pitchford No. 1, SE SW, Section 10, is from the Cypress B sandstone of the initial discovery subsidiary pool and should represent original formation brine. The Thompson No. 7 is one of the few wells completed in the Cypress A sandstone. The brine sample from this well therefore represents the Cypress A sandstone and should be uncontaminated by the waterflooding of the primary Cypress B and C sandstones. Brine water resistivities of these samples measured between 0.068 and 0.077 ohm-m at 77°F and may be useful for calculations requiring an R_w value. Resistivity values from the Pitchford No. 1 and the Thompson No. 7 are 0.068 ohm-m and 0.072 ohm-m, respectively, and are least likely to be influenced by reinjected fluids.

Volumetrics

Original oil in place (OOIP) and stock tank original oil in place (STOOIP) were determined for the Cypress B, C, and D sandstones. The recovery factor was also calculated for the entire field. An adjustment in the cumulative production for the field is necessary to more accurately calculate the recovery factor because an unknown quantity of Cypress A sandstone production is included in the cumulative value. Six to eight wells appear to have produced from the Cypress A interval.

Calculation of the volumetrics of the Cypress A sandstone is not feasible because (1) producing horizons and sandstone lenses are noncorrelative, (2) some perforations are below the oil–water contact, and (3) in the Thompson No. 7, the oil-bearing horizon lies below the oil–water contact for the rest of the field. Total production data from the Cypress A interval is not available because of commingled production with the Cypress B and C intervals and the reporting of production by lease rather than by individual well. An arbitrary quantity of 100,000 barrels (12,000–16,000 BO/well) was subtracted from the total field production in order to adjust the recovery efficiency value to reflect production from only the Cypress B, C, and D intervals. The OOIP was calculated using the standard volumetric formula:

$$\text{OOIP} = 7{,}758 \times H \times A \times \phi \times (1 - S_w)$$

where

7,758 = barrels of oil/acre-foot

H = height (thickness in feet) of net reservoir sandstone

A = area (in acres) of net reservoir sandstone

ϕ = average porosity of reservoir sandstone

S_w = water saturation of reservoir sandstone

An average porosity value of 20%, determined from the 11 available core analyses in the field, was used in the volumetric calculations for the Cypress B and C sandstones. An average porosity value of 17%, also determined from core, was used for the Cypress D sandstone. A conservative water saturation value of 40% was assumed for calculations. Calculations of water saturation from logs that show a definite oil response (oil leg) range from approximately 30% to 45%. The height (thickness) and area of net reservoir sandstones were determined from the thickness maps (figs. 9, 10, and 11).

STOOIP represents the conversion and reduction of oil volume at original reservoir pressure to oil volume at atmospheric conditions. A reduction in oil volume is caused by the release of solution gas dissolved in the oil at reservoir pressure as the confining pressure on the oil approaches atmospheric pressure. The assumption that solution gas is the driving mechanism for these reservoirs requires this conversion.

The quantity of solution gas in any particular reservoir varies. Without actual laboratory or field data from a reservoir, a value for the conversion factor or formation volume factor (B_{oi}) must be assumed. The most commonly used values in the Illinois Basin range from 1.10 to 1.15. Considering the low hydrostatic pressure values from drill stem tests and the low volume of gas recovered on these tests, a B_{oi} value of 1.10 was used for the Richview volumetric calculations. STOOIP is calculated by dividing the OOIP by the formation factor.

The volumetric calculations (in barrels of oil) using the factors described above are as follows:

Cypress D sandstone OOIP	=	863,000
STOOIP	=	785,000
Cypress C sandstone OOIP	=	3,551,000
STOOIP	=	3,228,000
Cypress B sandstone OOIP	=	3,297,000
STOOIP	=	2,998,000
Total OOIP	=	7,711,000
Total STOOIP	=	7,011,000

Cumulative oil production for Richview Field is 3.3 million barrels. The Cypress B, C, and D cumulative oil production is 3.2 million barrels, after subtracting 100,000 barrels of Cypress A sandstone production as mentioned above. The recovery factor of the combined Cypress B, C, and D sandstones is therefore 45.6%. Recovery factors for the separate sandstones cannot be calculated from the readily available data because data are commonly reported only by lease and are likely to include commingled Cypress production values.

RECOMMENDATIONS FOR DEVELOPMENT AND PRODUCTION STRATEGY

Each stage of reservoir development—from the drilling of the discovery well to the final abandonment of a reservoir—should employ a strategy to optimize production. A comprehensive, detailed discussion regarding the methods and techniques available to achieve optimum production from a field is beyond the scope of this publication, but some recommendations, based on observations of the Richview Field and comparisons of data, can be offered.

Various field studies have established that the most effectively drained reservoirs are those that have been developed by one operator or those that, through a coordinated effort, incorporate all operators from separate leases into a single waterflood program. Examples of increased efficiency from a field operated by a single producer or where production has been unitized and coordinated include Tamaroa Field (Grube 1992), Energy Field (Udegbunam and Huff 1994), and Zeigler Field (Sim et al. 1994, Seyler 1998).

Waterflood and Pressure-Maintenance Programs

Waterflood and pressure-maintenance programs are the most effective ways to increase cumulative production. Drilling and completion techniques, especially those preventing formation damage due to alteration of indigenous clay minerals, also can influence the amount of recoverable reserves. Finally, while enhanced oil recovery (EOR) programs (for example, carbon dioxide treatment) are proving economical and gaining technical acceptance, Fisher and Galloway (1983) found that in Texas, intensive development and infill drilling most effectively extend and increase production from an oil field. They base this finding on the amount of oil recovered by EOR techniques. Ninety percent of the EOR programs for this study are miscible gas flood programs.

Retaining reservoir energy is crucial to maximizing recovery efficiency, particularly in a reservoir of limited extent with a correspondingly limited drive. Initiation of waterflood projects early in the life of production at Richview Field probably retained or at least reestablished reservoir energy. The high recovery factor (45.6%) calculated for Richview Field is likely to be partly the result of these pressure-maintenance waterflood projects.

A potential problem with waterflooding of Mississippian sandstone reservoirs such as those at Richview Field is that the stacking or shingling of reservoir sandstones creates discrete compartments that can be bypassed by a waterflood. This situation can develop either where a compartment is not present in an injection well but is present in the offseting producer(s) or where the injector well (probably a converted producer) penetrates a compartment that is not in communication with a producer. Primary production is therefore drained from the separate compartment while the waterflood, in communication through another compartment or multiple compartments, bypasses the separate compartment. Stratigraphic correlations between vertically stacked or shingled, discontinuous reservoir compartments are not always obvious. A misunderstanding of these characteristics can lead to miscorrelations that consequently inhibit development and production.

Within Richview Field, the north to south thickening of the Cypress C sandstone results from shingling or stacking of additional sandstone lenses, some of which may contain bypassed oil as described above. Also, compartments may exist in the northern part of Section 2 where the general northeast–southwest trend of the Cypress B and C sandstones is cross-cut by northwest–southeast-trending reentrants and salients. A possible interpretation here is that a northwest–southeast-trending channel may have dissected the sand ridge and caused a break in the northeast–southwest-trending flow units. While the ridge deposits and the channel deposits may appear correlative on logs, impermeable zones may be present at the transition between the two deposits. The impermeable zone at this transition will divide the reservoir into compartments.

A similar waterflood problem develops where multiple stacked reservoir sandstones are present in a waterflood unit but permeability variations between compartments are great enough to channel the flood away from the compartments with lower permeability. In this case, the less permeable compartments contain bypassed, movable oil. Even compartments with increased permeability away from the wellbore contain bypassed oil. Because hydraulic fracturing was a common completion practice in many of the Mississippian stacked sandstone reservoirs in Illinois, including Richview, the capability to selectively flood a lower-permeability compartment may be limited. The induced fractures are typically designed to propagate through all compartments within the oil column and cause communication between all compartments. Therefore, a particular compartment cannot be isolated for flooding.

Reservoir continuity and flow unit correlation should be evaluated through use of field pressure analyses, including pulse, interference, build-up, draw-down, and tracer tests (Lee 1982). Pressure maintenance and other reservoir management requirements can also be evaluated using field tests and accurate, well-specific production histories that include water and, if possible, gas production.

Avoiding Clay Damage Caused by Drilling and Completion Techniques

While their effects on cumulative production are not as obvious as waterflooding, drilling and completion techniques can be significant factors for both short-term initial production and overall cumulative production. Evaluation of well performance at Tamaroa Field (Grube 1992) established that wells with open hole completions that did not drill deeper than the reservoir, and particularly wells that were completed using standard tools (cable) to penetrate the reservoir, tend to have the greatest cumulative production and higher initial production rates. These findings suggest that these Cypress sandstones may be susceptible to formation damage by drilling fluids or completion procedures. Drilling fluids, both the filtrate and the fines portion, can reduce permeability during invasion either (1) by dislodging clay-sized fines that migrate and catch in pore throats (2) or by clogging pore throats near the wellbore with drilling fines.

Fluids introduced into the reservoir during drilling, completion, and other development procedures can interact with the diagenetic kaolinite, chlorite, and mixed-layer illite/smectite common to many of the Cypress reservoirs. Interaction of these clay minerals with the introduced fluids can significantly reduce the permeability of the reservoir.

Although clay minerals are minor constituents in the Richview sandstones, they are in almost total contact with drilling, completion, and development fluids because they line pores and pore throats. Because clay minerals have a high surface-area-to-volume ratio, they are very susceptible to alteration, which consequently damages the formation when fluids are introduced.

Kaolinite, the dominant clay mineral in the Richview reservoirs, generally is chemically stable in the presence of the commonly introduced drilling, completion, and development fluids as long as the salinity of the introduced fluids does not greatly differ from the original brines. However, the diagenetic kaolinite is very loosely attached to the surface of host grains and can be easily dislodged and moved by fluids. Kaolinite particles can then migrate into pore throats, where they lodge, decrease permeability, and reduce production flow. This process occurs, particularly in the area close to the wellbore, where fluid flow rates reach velocities capable of migrating these particles. Clay stabilization systems are available that can easily resolve this potential problem, as long as treatment is applied early in the history of the well (Almon and Davies 1981).

Mixing incompatible brines can also cause kaolinite migration damage (Vaidya and Fogler 1990). “Water shock,” a term Vaidya and Fogler applied to an abrupt change in salinity in a reservoir, leads to a rapid and drastic decline in permeability. The shock is caused by introducing fresh or low-salinity water into a reservoir containing normal- to high-salinity brine. This problem can be avoided in the case of a waterflood by gradually lowering the salinity of an injection fluid, or in the case of drilling fluids by using a brine that is compatible with the reservoir being drilled (Vaidya and Fogler 1990).

Illite and mixed-layer illite/smectite clay minerals also react adversely to changes in water salinity. These clay minerals can swell when subjected to fresh water (Grim 1947, Allen and Roberts 1989). Swelling of these clays also decreases permeability.

Chlorite that has a high iron content is a clay mineral that is widespread in the Cypress sandstones. High-iron chlorite is extremely sensitive to acid and to oxygenated waters (Almon and Davies 1981). It dissolves readily in dilute HCl, and the liberated iron reprecipitates as an iron hydroxide gel when the acid is spent. This iron hydroxide clogs the pore throats, effectively blocking the production flow paths. This potential problem can be avoided if an oxygen scavenger and an iron chelating agent are added to the acid and all the treatment fluid introduced into the reservoir is recovered. Because of the minor amount of calcite in the Richview reservoirs, the only practical use of acid is for mud clean-up during completion. Even then, Almon and Davis (1981) recommend that an oxygen scavenger and an iron chelating agent should be used and that all acid should be removed from the hole rapidly. Almon and Davis (1981) further recommend that if ferric hydroxide has been precipitated in the reservoir due to an inadequately designed acid treatment, it can be removed by treatment with weak (5%) HCl combined with appropriate iron chelating agents and an oxygen scavenger. They strongly recommended that all acid should be recovered before it is spent.

Almon and Davies (1981) further recommend that any program that introduces fluids into a reservoir be designed for the specific clay mineral(s) in that reservoir. Therefore, a mineralogical analysis of the reservoir, particularly of the clay mineral(s), is highly recommended prior to introduction of fluids into the system. Four suggested clay mineral analyses are: (1) scanning electron microscope (SEM) with energy dispersive X-ray (EDX) analyzer, (2) X-ray diffraction analysis of the fine fraction (reservoir clays alone), (3) petrographic analysis by thin section, and (4) bulk X-ray diffraction analysis. At the very minimum, analysis by SEM-EDX will reveal where the clay minerals are located and indicate most types of clay minerals and their relative iron content.

Brine analysis, although not mentioned by Almon and Davies (1981), should be included; the composition of the introduced fluids must also be known to evaluate the potential chemical reactions that may occur between the components of the reservoir, particularly reservoir fluids, and the introduced chemicals. Iron materials used in oil well installations, such as casing and tubing, should also be considered as a reactive material that can affect the reservoir. An optimum drilling and development program that avoids formation damage can then be designed based on these results.

Infill Drilling

Infill drilling of Richview Field may prove to be economically feasible. Whitaker and Finley (1992) found that 10-acre well spacing and a 5-spot waterflooding program combined with off-pattern infill wells yielded an estimated recovery efficiency of more than 49% and possibly as much as 60% (Steven Whitaker, personal communication 1992) from marine bar-type reservoirs at Bartelso Field. Considering the similarity of the reservoir characteristics at Bartelso and Richview Fields, infill drilling to increase the recovery efficiency from 45% to 60% may be warranted.

Infill drilling may be required to assess the degree of reservoir compartmentalization that exists throughout the Richview area. The compartments related to the stacking of the Cypress C sandstone and the complication in the northern part of Section 2 where a channel appears to cut across the northeast–southwest-trending reservoirs may have to be evaluated by infill drilling.

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APPENDIX A CYPRESS RESERVOIR FLUID ANALYSIS

API Number 121890191900
Operator Thompson/Evans
Well Name George Thompson No. 7
Location NE NW SE, Sec. 35, T1S R1W
Reservoir Depth (ft) 1,532
Surface Elevation (ft) 553 (ground level)
Water Flooded Yes

Brine Analysis

Brine sample number EOR-B24
Resistivity 0.0719 ohm-m @ 25°C
Eh (mV) −99
pH 7.02
Total dissolved solids 113,763 ppm

Anion chemistry (mg/L)

Br	NA	I	NA
Cl	67,712	NO_3	NA
CO_3	NA	SO_4	NA
HCO_3	NA		

Cation chemistry (mg/L)

Al	NA	I	NA	Sb	<0.3
As	NA	K	186	Se	NA
B	3.28	Li	NA	Si	4.14
Ba	11.8	Mg	1,760	Sr	302
Be	NA	Mn	2.57	Ti	0.21
Ca	4,125	Mo	<0.05	V	NA
Cd	<0.05	Na	39,650	Zn	<0.02
Co	<0.05	NH_4	NA	Zr	0.1
Cr	NA	Ni	<0.15		
Cu	0.24	Pb	<0.4		
Fe	8.0	Rb	NA		

Oil Analysis

Oil sample number EOR-021

Hydrocarbon fraction (%)

Saturated hydrocarbons	19.11
Aromatic hydrocarbons	32.84
Resins	20.14
Asphaltenes	2.42

Selected hydrocarbon ratios

C17/C18	1.02
Pristane/Phytane	1.82
C17/Pristane	0.85
C18/Phytane	0.47

APPENDIX A *continued*

API Number 121890182700
Operator N.A. Baldridge
Well Name Weisbecher Community No. 1
Location NW SW SW, Sec. 2, T2S R1W
Reservoir Depth (ft) 1,482
Surface Elevation (ft) 550 (KB)
Water Flooded Yes

Brine Analysis

Brine sample number EOR-B25
Resistivity 0.0771 ohm-m @ 25°C
Eh (mV) −193
pH 6.56
Total dissolved solids 104,201 ppm

Anion chemistry (mg/L)

Br	NA	I	NA
Cl	62,658	NO_3	NA
CO_3	NA	SO_4	NA
HCO_3	NA		

Cation chemistry (mg/L)

Al	NA	Fe	5.7	Pb	<0.4
As	NA	I	NA	Rb	NA
B	2.98	K	153	Sb	<0.3
Ba	90.5	Li	NA	Se	NA
Be	NA	Mg	1,270	Si	4.84
Ca	3,070	Mn	1.69	Sr	195
Cd	<0.05	Mo	<0.05	Ti	0.71
Co	<0.05	Na	36,750	V	NA
Cr	NA	NH_4	NA	Zn	<0.02
Cu	0.2	Ni	<0.15	Zr	0.09

Oil Analysis

Oil sample number EOR-022

Hydrocarbon fraction (%)

Saturated hydrocarbons	27.84
Aromatic hydrocarbons	27.60
Resins	8.55
Asphaltenes	1.8

Selected hydrocarbon ratios

C17/C18	1.09
Pristane/Phytane	1.96
C17/Pristane	0.83
C18/Phytane	0.46

APPENDIX A *continued*

API Number 121890183600
Operator Canter Drilling
Well Name Edwards Unit No. 1
Location SE SE SE, Sec. 3, T2S R1W
Reservoir Depth (ft) 1,474
Surface Elevation (ft) 525 (ground level)
Water Flooded Yes

Brine Analysis

Brine sample number EOR-B26
Resistivity 0.0758 ohm-m @ 25°C
Eh (mV) −131
pH 6.76
Total dissolved solids 106,489 ppm

Anion chemistry (mg/L)

Br	NA	I	NA
Cl	63,878	NO_3	NA
CO_3	NA	SO_4	NA
HCO_3	NA		

Cation chemistry (mg/L)

Al	NA	Fe	16.1	Pb	<0.4
As	NA	I	NA	Rb	NA
B	3.02	K	160	Sb	<0.3
Ba	26.5	Li	NA	Se	NA
Be	NA	Mg	1,390	Si	4.51
Ca	3,345	Mn	1.67	Sr	216
Cd	<0.05	Mo	<0.05	Ti	0.18
Co	<0.05	Na	37,450	V	NA
Cr	NA	NH_4	NA	Zn	<0.02
Cu	0.18	Ni	<0.15	Zr	0.09

Oil Analysis

Oil sample number EOR-023

Hydrocarbon fraction (%)

Saturated hydrocarbons	26.01
Aromatic hydrocarbons	29.10
Resins	5.87
Asphaltenes	1.43

Selected hydrocarbon ratios

C17/C18	1.03
Pristane/Phytane	1.87
C17/Pristane	0.89
C18/Phytane	0.49

APPENDIX A *continued*

API Number 121892407200
Operator Elmer Oelze, Jr.
Well Name Pitchford No. 1
Location SE SE SW, Sec. 10, T2S R1W
Reservoir Depth (ft) 1,530
Surface Elevation (ft) 582 (ground level)
Water Flooded No

Brine Analysis

Brine sample number EOR-B27
Resistivity 0.0676 ohm-m @ 25°C
Eh (mV) –209
pH 6.91
Total dissolved solids 122,960 ppm

Anion chemistry (mg/L)

Br	150	I	NA
Cl	75,000	NO_3	<0.04
CO_3	0.03	SO_4	<1
HCO_3	88	NH_4	46

Cation chemistry(mg/L)

Al	<0.04	Fe	5.7	Pb	<0.4
As	<0.5	I	NA	Rb	NA
B	1.6	K	172	Sb	1.2
Ba	14.2	Li	6.31	Se	<0.7
Be	0.011	Mg	2,040	Si	3.3
Ca	5,120	Mn	3.22	Sr	302
Cd	<0.05	Mo	<0.08	Ti	0.04
Co	<0.07	Na	40,010	V	<0.08
Cr	<0.07	NH_4	NA	Zn	<0.02
Cu	<0.05	Ni	<0.1	Zr	<0.08

Oil Analysis

Oil sample number EOR-024

Hydrocarbon fraction (%)

Saturated hydrocarbons	41.54
Aromatic hydrocarbons	22.16
Resins	6.42
Asphaltenes	1.9

Selected hydrocarbon ratios

C17/C18	1.03
Pristane/Phytane	1.98
C17/Pristane	0.86
C18/Phytane	0.45

APPENDIX B RESERVOIR SUMMARY

Field Richview

Location Washington County, Illinois

Tectonic/Regional Paleosetting Intracratonic Basin

Geologic Structure Saddle along anticline

Trap Type Structural/stratigraphic

Reservoir Drive Gas solution

Original Reservoir Pressure NA; DST shut-in pressures range up to 480 psi

Reservoir Rocks
- **Age** Mississippian (Chesterian)
- **Stratigraphic unit** Cypress
- **Lithology** Quartz arenite
- **Wetting characteristics** NA
- **Depositional environments** Marine tidal ridges, vertically stacked
- **Productive facies** Sandstones of the clean, central ridge
- **Petrophysics** (ϕ and k from unstressed conventional core; Cypress B and C sandstones)

	Average (%)	Range (%)	Cutoff (%)
ϕ	20	14–26	16
k air (md)	175	3.5–752	100
k liquid	NA	NA	NA
S_w	NA	30–45	NA
S_{or}	NA	NA	NA
S_{gr}	NA	NA	NA
Cementation factor	NA	NA	NA

Source Rocks
- **Lithology and stratigraphic unit** New Albany
- **Time of hydrocarbon maturation** Permo-Triassic
- **Time of trap formation** Chesterian (stratigraphic); Pennsylvanian/Permian (structural)

Cypress Reservoir Dimensions
- **Depth** 1,480 ft (−940 ft, subsea elev.)
- **Areal dimensions** 667 net acres
- **Productive area** As above
- **Number of pay zones** 3
- **Hydrocarbon column** 42 ft (Cypress B and C interval combined)
- **Initial fluid contacts** Oil–water = −963 ft
- **Avg. net sand thickness**
  - Cypress B = 9.0 ft; south offset = 4 ft
  - Cypress C = 9.9 ft
  - Cypress D = 2.0 ft
- **Initial reservoir temperature** 96°F (estimated from logs)
- **Fractured** Hydraulically induced

APPENDIX B *continued*

Wells

Spacing 10 acre primary

Pattern Normal in Section 35 and north half of Section 2, variable in south half of Section 2 and in Sections 3, 10, 11, and 15

Total Producers 89, Water source 1, Observation 0, Suspended NA, Injection 11, Disposal 1, Abandoned 37 (recorded), Dry holes 53

Reservoir Fluid Properties

Hydrocarbons

Type oil and gas

Gas–oil ratio NA

API Gravity 37° to 39°

B_{oi} 1.10 (estimate)

Viscosity 4.7 cp to 4.9 cp @ 73°F, 3.3 cp @ 84° F

Bubble point pressure NA

Formation water

Resistivity 0.077 to 0.068 ohm-m at 77°F

Total dissolved solids 104,000–123,000 ppm

Volumetrics

In-place 7,011,000 BO STOOIP (total)

Cypress D sandstone	785,000
Cypress C sandstone	3,228,000
Cypress B sandstone	2,998,000

Cumulative production 3,345,000 BO through Dec. 1995

Ultimate recovery 3,500,000 BO

Recovery efficiency

Primary 17.6%

Secondary 28.0%

Tertiary none

Typical Drilling/Completion/Production Practices

Completions Most wells were cased through pay, perforated with two to four shots per foot and hydraulically fractured.

Drilling fluid Fresh water mud with gel additive

Fracture treatment Most fracture stimulations utilized from 2,000 to 5,000 gallons of crude oil with 2,000 to 5,000 pounds of 20–40 mesh sand propant.

Acidization None; perforation cleanup only

Producing mechanism Primary = pump; secondary = pump

Typical Well Production (to date)

Average initial production (IP) 56 BOPD; Range <1 to 180 BOPD main field, 11BOPD southern offset, 30 BOPD southeastern offset

Cumulative production NA

Water–oil ratio (initial) NA